The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 07-50-A July 16, 2008

Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources.

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I. SUMMARY

A. Overview

In today's Order, the Department of Public Utilities ("Department") sets forth a plan for establishing a new base rate adjustment mechanism, or "decoupling," to be adopted by jurisdictional electric and natural gas distribution companies ("distribution companies") in the Commonwealth. This is a necessary evolution of Department ratemaking practices – it will help us address some of the profound impacts of increases in the costs of natural gas and electricity on the Commonwealth's residents and businesses. It will also provide distribution companies with better financial incentives to pursue a cleaner, more efficient energy future consistent with the recently enacted legislation, Chapter 169 of the Acts of 2008, An Act Relative To Green Communities ("Green Communities Act"). Today's Order paves the way for the aggressive expansion of demand resources (i.e., energy efficiency, demand response, combined heat and power, and renewable generation) in Massachusetts in a manner that fully maintains and enhances fundamental and long-standing Department precedent on ratemaking principles and consumer protections for all consumers of electricity and natural gas in the Commonwealth.

This Order is a simple, albeit critical, first step in altering the regulatory landscape in Massachusetts in a way that will fully align the financial interests of the shareholders of our investor-owned distribution companies with the economic and environmental imperatives facing us today. Distribution companies must have the proper regulatory and financial incentives to fully pursue the economic, price, reliability, and environmental benefits that are available from (1) improving the efficiency of energy production, delivery, and consumption; (2) building a strong and effective price-responsive demand; (3) fostering the rapid development of renewable energy and distributed generation within Massachusetts; and (4) supporting the evolution towards a more efficient distribution infrastructure. The Department takes this action today recognizing that these goals must be met if we are to help mitigate our vulnerability to significant increases in energy commodity prices and to prepare our energy industries for the unavoidable future of a carbon-constrained world.

Moving forward, the Department will continue these efforts with proceedings to implement the groundbreaking provisions of the Green Communities Act including proceedings related to renewable power procurement, net metering, and the expansion of energy efficiency programs in the Commonwealth. Today's Order provides the underlying ratemaking foundation for those continued efforts.

B. Rationale for a New Base Rate Adjustment Mechanism and Department Response

The Department's rationale for moving to a new ratemaking approach starts with a sobering reality: prices for electricity and natural gas service in the Commonwealth are higher than they have ever been. Current price levels for electricity and natural gas make it more difficult for many of the Commonwealth's residents to pay their utility bills, compound the impact of increases in other costs for all residents, and increase input costs for our businesses and industries.

The surges in energy prices are tied to the cost of the wholesale energy commodity itself – to the natural gas that is burned in residences, in businesses, and in the power plants that generate electricity in New England. The prices for transmission and distribution services, on the other hand, have remained relatively constant or have increased at a modest pace in recent years. In 1998, commodity natural gas represented approximately 52 percent of total gas customers' bills on average; today, that stands at 73 percent, and is climbing. Similarly, in 1998 the commodity/generation portion of electric customers' bills amounted to 30 percent of the total bills; today, that stands at 65 percent, and this percentage is also climbing.

The costs of electricity and natural gas commodities in the Commonwealth are determined primarily by market prices of the underlying fuels, particularly natural gas. These prices are set in national and, increasingly, international markets that are subject to regional, national, and international conditions of supply and demand. These energy market commodity prices are, for all intents and purposes, beyond the direct control of state regulators and to a certain extent most market participants, and the impact of commodity price increases affects competitive and basic service customers alike.

These are the conditions that drive the Commonwealth's energy policy towards expansion of energy efficiency, robust demand response, combined heat and power, and renewable generation. These demand resources represent the single most effective tool we have to mitigate the increases in and volatility of commodity gas and electricity prices. Demand resources allow participating host customers to significantly reduce their own energy bills. They also create downward pressure on wholesale gas and electric prices by lowering regional demand, thereby helping to lower energy bills throughout Massachusetts and the region.

The enactment of the Green Communities Act provides a springboard for the Department to carry on its goals to address energy costs and provide consumers with an opportunity to better manage their energy use, thereby helping to mitigate costs and address important societal and environmental needs. Many of the provisions of the Green Communities Act, as they relate to demand resources, can be strongly supported by complementary Department policies. In adopting decoupling, the Department establishes the first and most important such policy mechanism: the elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts.

In its Order opening this investigation, the Department proposed to address these financial barriers through a base revenue adjustment – or decoupling – mechanism, and presented a straw decoupling proposal in order to focus the scope of the proceeding and the comments of interested persons. There has been vigorous participation in this investigation by many interested companies and persons, and the Department has received a wide array of instructive and valuable comments. The Department appreciates the interest and active participation of all parties.

In the sections that follow, we summarize the comments received and present our findings with respect to the many issues considered in the course of this proceeding. Specifically, we establish a comprehensive plan for decoupling to be adopted by jurisdictional electric and natural gas distribution companies on a going-forward basis. The decoupling approach adopted today has benefitted from the comments of all parties and departs from the Department's straw proposal in significant ways. Specifically, the Department concludes the following:

- That gas and electric distribution companies shall implement fully decoupled rates.
- That performance based regulation ("PBR") plans may be included in a decoupled rate structure if a Company can demonstrate that they are still warranted.
- That existing rate plans and PBR plans may continue until the end of their terms.
- That reconciliation filings will be annual, with an additional filing if the company exceeds a threshold ten percent above or below target revenues.
- That any quantification of a change in risk due to decoupling is subject to a wide range of considerations which would be properly considered along with all other factors affecting return on equity ("ROE") as part of a rate case.
- That there will be an opportunity for companies to receive lost base revenue ("LBR") from incremental efficiency programs stemming from the Green Communities Act.
- That the decoupling of rates cannot properly be completed in a piecemeal fashion, such as through a stand-alone adjustment to existing rate designs.
- That the principle of shareholder incentives will be maintained but may be revised.

II. INTRODUCTION AND PROCEDURAL HISTORY

On June 22, 2007, the Department issued an Order opening an investigation into rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand resources in Massachusetts.[1] Investigation Into Rate Structures, D.P.U. 07-50 (2007). The purpose of the investigation was to review the current ratemaking practices by which distribution companies in the Commonwealth recover their prudently incurred, just and reasonable costs, and to consider whether these practices should be changed. Id. at 1. The Department stated that we would consider whether distribution companies' financial interests should be better aligned with the need to: (1) capture all available and economic system and end-use efficiencies and their associated reliability, economic and environmental benefits; and (2) foster the advancement of price-responsive demand in regional wholesale energy markets. Id.

Specifically, the Department recognized that distribution companies' incentives to increase sales and avoid any decrease in sales may not be well-aligned with important state, regional, and national goals to: (1) promote the most efficient use of society's resources; (2) lower customer bills through increased end-use efficiency; (3) enhance the price-responsiveness of wholesale electricity markets; (4) mitigate the social and economic risks associated with climate change; and (5) minimize the environmental impacts of energy production, transportation, and use. Id. at 2. We stated that the purpose of the inquiry was to

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1 Demand resources are installed equipment, measures or programs that reduce end-use demand for electricity or natural gas. Such measures include, but are not limited to, energy efficiency, demand response, and distributed resources.

establish guidelines to govern the Department's approach to ratemaking, while fulfilling our statutory obligation under G.L. c. 164, § 94 to investigate the propriety of any rate, price or charge collected within the Commonwealth for the sale and distribution of electricity or natural gas. Id. at 1.

As part of the inquiry, the Department presented a straw proposal for a base revenue adjustment mechanism for comment from interested persons. By including this straw proposal, the Department intended to: (1) provide initial guidance; (2) foster consideration of appropriate mechanisms; and (3) help focus the scope of the proceeding and the comments of interested persons. Id. at 3, 10. This base revenue adjustment mechanism was intended to render distribution companies' revenue levels immune to changes in sales between rate proceedings by severing the link between electric and gas companies' revenues and sales. Id. at 3, 11. The proposed base revenue adjustment mechanism tied distribution company revenues to the number of customers served but retained unit-based energy and demand pricing to preserve the link between customers' costs and their levels of consumption. Id. at 3, 13, 15. The Department postulated that the major cost driver for distribution companies is the number of customers, and that the proposed base revenue adjustment mechanism could make certain features of current rate plans obsolete (e.g., performance based ratemaking ("PBR") plans). Id. at 5, 18. The Department proposed to reconcile actual revenues to a revenue target and further proposed methods of determining and reconciling actual revenues versus target revenues, with reconciliations that would be performed on an annual basis, including quarterly informational filings. Id. at 4, 16. We suggested that a full base rate proceeding may be needed to properly design each base revenue adjustment mechanism and that decoupling could materially alter the distribution of risks among a distribution company, its shareholders, and its customers. Id. at 4, 17. Finally, we proposed that lost base revenue ("LBR") recovery be terminated upon the implementation of a base revenue adjustment mechanism and stated that a schedule would be developed for implementing the base revenue adjustment mechanism for each distribution company in an expeditious manner. Id. at 18-19.

During the investigation, the Department issued one set of information requests, solicited two rounds of written comments, and convened panel hearings on various topics. The information requests were issued to all distribution companies.[2] Initial comments ("Comments") were filed by 35 interested persons.[3] Reply comments ("Reply Comments") were filed by 20 interested persons.[4] At their request, a total of 25 entities participated in the five days of panel hearings before the Department and raised numerous issues both in written comments and at the hearings.[5]

After consideration of the comments received in this proceeding, the Department concludes that a full decoupling mechanism, similar to the base revenue adjustment mechanism included in our straw proposal, is needed to reduce or eliminate the current financial

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2 The information requests, issued June 28, 2007, sought sales information between 1999 and 2006.

3 For a complete list of initial comments filed and memorializations used hereafter, see Appendix 1.

4 For a complete list of reply comments filed, see Appendix 2.

5 For a complete list of participants in the panel hearings, see Appendix 3.

disincentive that electric and gas companies face regarding the deployment of customer-sited, cost-effective demand resources in their service territories (see Section III, below). In Section IV, the Department addresses several issues associated with the mechanics of implementing a full decoupling mechanism, including distribution cost drivers, revenue reconciliation, and rate adjustments. In Section V, the Department reviews the effect that implementation of a base rate adjustment mechanism could have on a distribution company's risk. In Section VI, the Department addresses how distribution companies will make the transition to a base rate adjustment mechanism. Finally, in Section VII, the Department describes the required elements of a base rate filing to implement decoupling.

The establishment of a base revenue adjustment mechanism is within the Department's broad ratemaking authority. Pursuant G.L. c. 164, § 94, the Legislature authorized the Department to regulate the rates, prices, and charges that distribution companies may collect. See Boston Edison Company v. City of Boston, 390 Mass. 772, 774-775 (1984). The Department is not compelled to use any particular method for calculating the base rate, provided that the end result is not "confiscatory" (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment), a matter in which the distribution company bears the burden of proof. Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 19 (1978).

As noted in Section I, the Department recognizes that implementation of a decoupling mechanism by itself will not result in an increased deployment of demand resources – this will only result from actions taken by the distribution companies, demand resource service providers, and customers. As such, the directives contained in this Order are but the first in a series of steps the Department intends to take regarding the efficient deployment of demand resources. By establishing regulatory certainty in this proceeding regarding the recovery of revenues lost due to reduced sales, the Department can work with stakeholders to develop additional policies and plans regarding the efficient deployment of demand resources.

III. RATEMAKING MECHANISMS TO SUPPORT THE OPTIMAL DEPLOYMENT OF DEMAND RESOURCES

A. Introduction

In our current ratemaking model, once distribution companies' rates are determined through base rate proceedings, they have a strong incentive to take actions to increase sales (thereby increasing revenue) and an equally strong incentive to avoid any decrease in sales (thereby decreasing revenue). D.P.U. 07-50, at 2. Because demand resources are located on the customer side of the meter, they will always reduce a distribution company's sales. This inherent conflict between the incentive to increase sales and the reduced consumption resulting from the use of demand resources creates a barrier to the efficient deployment of these important resources. Id. at 3.

The Department's straw proposal sought, among other things, comment on a full decoupling mechanism in which a distribution company's revenues are separated from changes in consumption, regardless of the underlying cause of the change. Id. at 12-16. The Department also requested that commenters address the extent to which other ratemaking approaches would eliminate the financial disincentive that the distribution companies currently face regarding the efficient deployment of demand resources in their service territories, including: (1) partial decoupling, where changes in sales unrelated to the deployment of demand resources would not be included in the decoupling mechanism; (2) targeted decoupling, where only changes directly resulting from the company's demand resource programs would be included in the decoupling mechanism; (3) shareholder incentives, where an approach similar to that currently used for energy efficiency programs would be applied to other demand resources; and (4) a redesign of base rates, in which a greater portion of revenues would be collected through fixed and demand-based rates.

B. Summary of Comments

1. Commenters Opposed to Full Decoupling

While all commenters support the Department's objectives for opening this investigation, for various reasons, a number of commenters oppose the implementation of a full decoupling mechanism. Some commenters argue that there is an absence of evidence that decoupling is necessary (AIM Comments at 5-6; AIM Reply Comments at 2; Attorney General Comments at 6; Attorney General Reply Comments at 3; Tr. 2, at 241-242; TEC Comments at 1-2; WMIG Comments at 2, 4). TEC states that distribution companies have the burden of proving that the magnitude and scope of energy efficiency programs and demand response initiatives would be enhanced by decoupling (TEC Comments at 12). TEC contends that its review of ratemaking practices in other states indicates that simply changing the structure of revenue recovery will not automatically cause distribution companies to deploy more demand resources (id. at 2). AIM questions the basic premise that distribution companies are presented with an inherent conflict that creates a barrier to the efficient deployment of demand resources

(AIM Comments at 5). AIM disputes the existence of such a conflict and advises the Department, before proceeding further, to determine whether there is a problem at all (AIM Comments at 5-6; AIM Reply Comments at 2). AIM states that there are ways to reduce energy costs without harming distribution companies, asserting that proposed energy legislation makes efficiency actions that reduce peak load a priority because peak load reduction results in significant infrastructure savings with little impact on distribution company revenues (AIM Reply Comments at 3). WMIG disputes the assumption that distribution companies will not cooperate constructively with the Legislature and the Department on the deployment of demand resources without additional revenue guarantees (WMIG Comments at 4). WMIG adds that, if true, it indicates a serious disregard for the public welfare that would be sufficient to question the wisdom of having any distribution company involvement in these programs (id.). In response to this perceived lack of evidence that decoupling is needed, the Attorney General proposes that the Department require the distribution companies to report all specific revenue losses associated with incremental demand resources (Attorney General Reply Comments at 27).

Other commenters who oppose full decoupling argue that it would prove ineffective to ensure an increased deployment of demand resources and may even cause harm. RESA states that while it supports the Department's articulated energy efficiency and conservation goals, it remains skeptical as to whether decoupling can generate enough benefits to offset the costs of implementation (RESA Comments at 2). RESA foresees unintended adverse consequences associated with such a departure from traditional ratemaking (id. at 1, 2, 7-9). RESA asserts that industry experts, interest groups, and policy makers in other states have rejected decoupling on legal, policy, and practical grounds (id. at 6-7). As such, RESA suggests that the Department carefully evaluate the potential benefits, costs, and risks associated with decoupling and, instead, pursue other efforts to increase the deployment of demand resources (id. at 6, 9-10, 13).

Mass Food, MHA, and NAIOP contend that decoupling will not address the high cost of electricity in Massachusetts (Mass Food Comments at 1-2; MHA Comments at 1-2; NAIOP Comments at 1-2).[6] MHA, GBREB, and NAIOP argue that decoupling will discourage their constituencies from pursuing energy efficiency or "green building" opportunities because it will reduce (or possibly eliminate) the savings and incentives realized from such activities (MHA Comments at 2; GBREB Comments at 2; NAIOP Comments at 2). MHA claims that, by guaranteeing a revenue stream for the distribution company paid by customers regardless of their electricity consumption, decoupling would eliminate the thoughtful regulatory analysis that is part of traditional ratemaking (MHA Comments at 2). Mass Food states that decoupling is not an efficient and equitable approach to reduce overall consumption. Mass Food contends that such a significant departure from traditional rate design and ratemaking is unnecessary and counterproductive (Mass Food Comments at 1-2).

RAM is concerned about the potential for decoupling to create unintended increases in consumer energy usage and cost shifts in the commercial class based on widely varying levels

[6] Mass Food states that the experience with decoupling in Maine, where some of its members also operate, indicates that decoupling did not lead to lower electricity costs (Mass Food Comments at 2).

of usage (RAM Comments at 3). Wal-Mart opposes decoupling because it is concerned about: (1) the proposed use of the number of customers as the proxy for consumption; (2) the potential to insulate distribution companies from cost variances that are not related to the implementation of energy efficiency; (3) the additional complexity of reconciliation filings; and (4) the challenge of rate stability (Wal-Mart Comments at 4-9; Wal-Mart Reply Comments at 2-4).

Some commenters state that, as an alternative to decoupling, the existing incentive and LBR mechanisms that apply to energy efficiency activities should be increased. The Network contends that the existing incentive system has created some of the most successful efficiency programs in the country, which have received national awards for quality, comprehensiveness, and efficiency of delivery (Network Comments at 1-2). The Network states that it would support a significant increase in spending on energy efficiency which, if implemented, would be an appropriate time to examine the existing incentive scheme to determine whether it needs revision (Tr. 1, at 57, 115). The Attorney General states that distribution company revenue losses resulting from the increased deployment of demand resources can be addressed through existing ratemaking mechanisms (Attorney General Reply Comments at 2-3). The Attorney General argues that if revenues are significantly affected by the deployment of demand resources, distribution companies could propose a targeted revenue recovery mechanism, such as LBR (id. at 27).

In contrast, other commenters question the role of distribution companies in the provision of demand resource programs going forward. AIM argues that distribution companies are sufficiently rewarded for existing energy efficiency programs and that there is no evidence that distribution company revenues are harmed by energy efficiency programs (AIM Comments at 7-8; AIM Reply Comments at 2). AIM states that, while distribution company-offered demand resource programs may have made sense in the past, it makes little sense now for distribution companies to remain key players in the energy efficiency market (AIM Comments at 8). AIM suggests that this may be the time to extricate distribution companies from demand resource programs and, instead, rely on market-based incentives, particularly for large commercial and industrial customers (id.).

RESA states that the Department should define the distribution companies' role in the deployment of demand resources in a targeted way that is designed to support, rather than undermine, the ability of the competitive market to offer a wide array of energy efficiency and demand response services that can bring significant value to all consumers (RESA Reply Comments at 5). In doing so, RESA argues that the Department would recognize the importance of the competitive market in the delivery of innovative energy efficiency and demand response programs and would define a role for the distribution companies that will leverage, rather than impede those competitive market forces (id. at 6). RESA recommends that the Department first define the role of the distribution companies in the deployment of demand resources before it settles on a particular decoupling mechanism (id. at 5). RESA acknowledges the good job that the distribution companies have done in administering energy efficiency programs and states that the companies are in a unique position to communicate energy efficiency options to mass market customers who remain on basic service (id. at 9).

RESA states that the distribution companies could educate customers about competitive supply options that include energy efficiency and demand response services though bill inserts, website information, and telephone contacts (id.). RESA asserts that if incentives are provided to distribution companies, incentives also should be provided to all market participants, including to customers, to use as they see fit.

Commenters suggest various other initiatives that the Department could pursue instead of decoupling. The Network states that there are many outstanding issues regarding the cost-effective deployment of demand resources that need to be addressed before proceeding with decoupling (Tr. 1, at 15; Network Comments at 2). The Network states that, once these issues are resolved, the Department can apply the existing targeted incentive or LBR method to other demand resources (Tr. 1, at 22, 23). As such, the Network recommends that the Department take no action and close this docket (Network Comments at 1, 10; Tr. 1, at 19).

The Attorney General suggests that the Department consider: (1) implementing an alternate rate design method that collects more fixed costs through rate elements that do not vary with consumption; (2) developing an optimal peak pricing pilot program open to all customers; (3) adopting of policies that support the deployment of smart technologies; and (4) implementing standby and back-up rates for distributed generation (Attorney General Comments at 32-35; Attorney General Reply Comments at 2, 23).

AIM recommends that the Department focus its resources on rate design and mandating individual rate cases (AIM Comments at 11; AIM Reply Comments at 3). RESA suggests that the Department (1) complete its investigation of standby and backup rates for distributed generation, (2) adopt a cost-based rate that appropriately recognizes the diversity of standby and backup customer demands, and (3) commence its investigation into dynamic pricing at the earliest possible date (RESA Comments at 13-16).

WMIG states that other measures are more effective than decoupling, other priorities more pressing, and other alternatives to solving distribution company incentive problems are less resource intensive, less risky to consumers and more effective at promoting energy efficiency (WMIG Reply Comments at 1). WMIG states that, even if decoupling could effectively remove distribution company incentives to expand service, it is an unjustified diversion of resources from the actual work of energy efficiency (id. at 4). WMIG claims that rate design is chief among the alternatives that would more effectively address improper volumetric incentives for the distribution companies (id.). WMIG states that the distribution companies' revenue requirements are dominated by fixed costs in the short term and by peak demand in the longer term. WMIG states that, in order to have a least cost system, costs must be allocated based on peak demand and, therefore, long-run marginal based rate designs are preferable (id. at 7-8). WMIG states that it does not recommend the immediate imposition of fully cost-based rate design but states that it must be a goal with a series of transitional steps identified to move cost allocation in the proper direction (WMIG Reply Comments at 9). Noting that manufacturing in Massachusetts continues to decline while residential loads continue to expand, WMIG states that proper cost of service principles and effective demand response requires an adjustment of inter-class revenue allocation to reflect costs (id. at 10). WMIG also suggests that the Department completes its investigation of standby and backup rates and adopt a cost based rate that appropriately recognizes the diversity of standby and backup customer demands (id. at 2, 4).

DOER states that, from the standpoint of economic efficiency, a straight fixed variable price structure, in which all fixed costs would be collected through a fixed customer charge, would eliminate current disincentives (DOER Reply Comments at 4). However, DOER opposes such a rate design arguing that it would reduce consumers' ability to achieve bill savings through energy efficiency measures (id. at 7-9).

Alternatively, certain commenters state that if the Department opts to pursue decoupling, then it must be of an appropriate design. TEC states that for a decoupling mechanism to be in the public interest, it must adjust rates only for changes in customer usage that are attributable to energy efficiency and demand response programs (TEC Reply Comments at 1). The Network states that the National Association of State Utility Consumer Advocates recently resolved to oppose decoupling mechanisms that would guarantee distribution companies the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases (Network Comments at 6). Wal-Mart states that, for a decoupling mechanism to be just, reasonable, and nondiscriminatory, it must allow distribution companies to recover only those revenue losses caused by the implementation of distribution company-sponsored energy efficiency measures. Wal-Mart states that risks associated with factors such as weather variations, economic conditions, and power outage events should remain with the distribution company to manage (Wal-Mart Reply Comments at 2-4). As an alternative approach to achieve efficiency goals, Wal-Mart suggests that the Department adopt (1) a rate design method that identifies and allocates costs based on customers' load characteristics; and (2) real-time pricing (Wal-Mart Comments at 3, 9-12; Wal-Mart Reply Comments at 3).

2. Commenters that Support Full Decoupling

A number of commenters support the implementation of full decoupling as a means to ensure an increased deployment of demand resources. DCG supports full decoupling, stating that it will align distribution company and customer interests to promote demand resource investments in a way that is superior to other mechanisms intended to achieve the same effect (DCG Reply Comments at 1).[7] Concentric states that, in a period when distribution company revenues are negatively affected by consumer- and program-driven conservation, decoupling mechanisms serve to: (1) remove the disincentives that are embedded in current ratemaking approaches; (2) improve the efficiency of rate regulation; and (3) make distribution rates more stable by avoiding frequent rate increases (Concentric Reply Comments at 2). DOER asserts that removing the disincentives inherent in existing rate structures is necessary to capture all cost effective energy efficiency (DOER Reply Comments at 3). DOER states that, if properly done, decoupling will reduce energy costs and result in savings for all consumers (DOER Comments at 1). However, DOER cautions that, if not done properly, decoupling could result in the protection of revenues for distribution companies without commensurate benefits (DOER Reply Comments at 2).

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[7] A number of interested persons formed a consensus position and submitted reply comments as the "Decoupling Consensus Group." For a list of group members, see Appendix 3.

Some gas distribution companies support full decoupling, citing certain conditions within the gas industry. Bay State argues that, for gas distribution companies, decoupling is essential to mitigate the revenue erosion associated with declining average use per customer (Bay State Reply Comments at 3). Bay State contends that a decoupling mechanism will position gas distribution companies to aggressively encourage their customers to increase the efficient use of energy and to embrace efficiency measures that may displace the use of natural gas or other fossil-burning fuels (id. at 2-3). Specifically, Bay State argues that there are many other opportunities for its customers to improve efficiency outside of its demand side management programs and that decoupling will encourage it to: (1) take on a more active advisory role for these measures; and (2) undertake education efforts that could increase energy savings (id. at 9-10).

Commenters who support full decoupling cite various reasons for their opposition to other forms of decoupling (i.e., targeted decoupling, partial decoupling, etc.) and LBR recovery. DOER prefers a full decoupling approach over a partial or targeted approach because full decoupling does not require the use of savings calculations that would be difficult to review (DOER Reply Comments at 5). Berkshire supports a full decoupling approach over the partial and targeted approaches, stating that full decoupling is far easier to administer because there is no need to determine whether lower use per customer was due to conservation measures installed by the company or other factors such as price increases, weather, or economic conditions (Berkshire Reply Comments at 3). DCG opposes a partial decoupling mechanism that normalizes sales for factors such as weather and economic conditions because it would require, at least for economic factors, a complex set of assumptions (DCG Reply Comments at 5-6). DCG also opposes a targeted LBR approach because companies would still have the economic incentive to maximize sales (id. at 8). DCG contends that the Department should not consider an LBR recovery scheme except as a limited, interim transitional measure to help facilitate immediate increases in distribution company-run programs (id. at 9).

Some commenters contend that full decoupling alone will not go far enough to achieve the Department's goals. Berkshire recommends that, as a complement to full decoupling, the Department implement an "enhanced" rate design in which a greater percentage of a company's fixed costs are collected through the customer charge (Berkshire Reply Comments at 4-5). DCG states that the implementation of a full decoupling mechanism is a necessary but not sufficient step to aligning distribution company and customer interest in more efficient energy use (DCG Reply Comments at 11-12). DCG states that, to fully align company and customer interests, the distribution companies must be motivated through the use of shareholder performance incentives to develop and administer cost-saving demand-side management ("DSM") programs (id. at 4, 12). Finally, DCG recognizes that there may be some merit in redesigning rates so that a company's fixed costs are recovered through fixed rates (id. at 10). However, DCG states that increasing fixed distribution charges and reducing volumetric distribution charges: (1) could reduce significantly the economic signals to customers to invest in cost saving demand resources; and (2) would have significant bill impacts for low-use customers (id. at 10-11). DCG states that such rate design should be pursued only over a reasonable transition period adequate to mitigate the bill impact for low-use customers (id. at 10). DOER supports the continuation of some incentive payment structure, although it acknowledges that the current structures will have to be revisited under a decoupled rates regime (DOER Reply Comments at 6). Finally, from the standpoint of economic efficiency, DOER states that collecting all fixed costs through the customer charge would eliminate current disincentives (id. at 4). However, DOER opposes such a rate design, arguing that it would reduce consumers' ability to achieve bill savings through energy efficiency measures (id. at 8).

3. Other Comments

EnerNOC states that competitive neutrality is needed to encourage widespread participation and innovation in demand-side offerings for customers (EnerNOC Comments at 3). EnerNOC emphasizes that decoupling should not create exclusivity, or any other unfair advantage or preferential treatment, for distribution companies regarding the provision of demand resource services (id.). EnerNOC argues that such advantage would undermine the effectiveness of the Department's overall objectives of promoting energy efficiency, conservation, and wise use of energy resources (id.). EnerNOC claims that if distribution company-only advantages are incorporated into program design, it will be a deterrent to third-party retail competitors that would otherwise participate in demand-side programs (id.).

The Compact states that a decoupling mechanism should not dramatically raise rates or completely protect a distribution company during severe economic downturns, when other entities in the Commonwealth are suffering (Compact Reply Comments at 1). As such, the

Compact favors a partial decoupling approach in which the revenue target would vary with the general level of economic factors in a distribution company's service territory (id.).

C. Analysis and Conclusions

1. Introduction

There was wide agreement among commenters that demand resources should play an increasing role in the provision of electric and gas services. We agree. It is imperative that we provide electric and gas customers with all available tools to lower their energy costs; this is particularly important given the magnitude of recent (and expected future) increases in the commodity prices for electricity and natural gas. Energy efficiency, demand response, and distributed generation offer residential, commercial, and industrial customers the greatest opportunity to reduce their electric and gas bills cost-effectively. These demand resources can help customers reduce all components of their bills including distribution, transportation, and supply.

A second and equally important benefit to be gained through the deployment of demand resources is increased efficiency and downward pressure on prices in wholesale energy markets, in particular the regional electricity markets. Regional wholesale costs and the impacts of price volatility have soared over the past decade, primarily due to large cost increases for the fossil fuels that power the majority of the region's supply resources. Wholesale costs now comprise almost 65 to 75 percent of the prices that many retail consumers pay for natural gas and electricity. Because of the lack of indigenous energy resources in our region, customers, regulators, and distribution companies have limited ability to mitigate the increased costs and volatility of regional wholesale electric and gas markets. In stark contrast, the aggressive pursuit of in-state and in-region demand resources can serve to reduce natural gas and electricity demand under high-load and high-stress conditions and set a lower overall baseline of energy consumption, resulting in a more efficient use of our supply resources, and leading to lower and more stable wholesale electricity costs. Importantly, the benefits of demand reduction in energy markets accrue to all electricity and natural gas consumers, not just those who implement efficiency, demand response, and other demand-reducing strategies and resources. Finally, the deployment of demand resources can provide broad societal benefits by (1) promoting the most efficient use of society's resources, (2) mitigating the social and economic costs associated with climate change, and (3) minimizing the environmental impacts of energy production, transportation, and use. D.P.U. 07-50 at 2.

It is now clear that the electric and gas industries will be subject to increasingly stringent regulations to limit greenhouse gas emissions. See e.g., 310 C.M.R. §§ 7.29(5), 7.70. Such regulations will create upward pressure on electric and gas prices over time. Energy efficiency and other demand resources currently offer the lowest-cost option for complying with such regulations and, thus, will play a key role in the Commonwealth's strategy for addressing climate change.

For all of these reasons, promoting the implementation of all cost-effective demand resources is a top priority for the Department and the primacy of this goal guides our consideration of the issues raised in this proceeding. It is our view that the deployment of all cost-effective demand resources will require the full participation of a broad group of stakeholders, including the electric and gas distribution companies, their customers, the manufacturers and distributors of efficiency equipment and products, and competitive providers of demand resource services. To realize the full potential of demand resources, it is essential that we leverage the distribution companies' relationships with customers, as well as with any other entities that will be engaged in the development and deployment of such resources. Perhaps most importantly, without the full support of electric and gas distribution companies, it will be very challenging to reach the goal of implementing all cost-effective demand resources.

2. Alternative Ratemaking Mechanisms

a. Introduction

In our Order opening this investigation, the Department stated that the mechanism by which we set rates should be designed to (1) align the financial interests of the distribution companies with policy objectives regarding the deployment of demand resources, and (2) ensure that distribution companies are not financially harmed by increased use of demand resources.[8] D.P.U. 07-50, at 11. We identified a full decoupling mechanism, one that would comprehensively sever the link between a distribution company's revenues and sales, as one approach that would meet these goals. In response, commenters put forth several alternate

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8 Other principles enunciated by the Department were to: (1) closely align distribution company revenues with costs; (2) ensure rate continuity, fairness, and earnings stability; (3) balance the risks borne by customers and shareholders; (4) ensure safe, reliable, and least-cost delivery service; (5) provide for uniformity across distribution companies; and (6) be simple, easily understood, and transparent. D.P.U. 07-50, at 11-12.

ratemaking mechanisms also designed to meet our stated policy goals including: (1) base rate redesign; (2) targeted decoupling; (3) partial decoupling; and (4) shareholder incentives.

b. Rate Redesign

Pursuant to St. 164 of the Acts of 1997 ("Restructuring Act") and other changes in the electric industry, the former system of vertically-integrated electric distribution companies has been supplanted by unbundled generation, transmission, and distribution companies. This has significantly altered the way that costs are incurred and electric rates are set in Massachusetts. Prior to restructuring, the Department set rates to recover the costs associated with generation, transmission, and distribution using traditional cost of service/rate of return ("COS/ROR") principles, as described below. With industry restructuring, only distribution rates continue to be set using COS/ROR regulation. In contrast, customers procure electric supply directly from retail competitive suppliers or, for customers remaining on basic service, from electric distribution companies through competitive solicitations where supplier costs are directly passed through to customers on a reconciling basis. The costs of transmission service are collected by companies under fully-reconciling rates, with charges set by the Federal Energy Regulatory Commission ("FERC").

Costs incurred by the gas distribution companies for the purchase, storage, and interstate transportation of gas, commonly referred to as gas supply costs, are recovered via the cost of gas adjustment clause ("CGAC") on a dollar-for-dollar basis. Like electricity supply costs, gas supply costs are fully reconciled. See 220 C.M.R. §§ 6.00 et seq. Similar to electric distribution service costs, gas distribution-related costs continue to be set under COS/ROR regulation, and are recovered via base rates.

Under COS/ROR regulation, the Department determines rates for distribution service through a three-step process. First, we determine a company's revenue requirement, based on its level of expenses, its allowable investment (or rate base), and a reasonable rate of return on rate base. Second, we determine the allocation of the revenue requirement to each rate class, based on cost-causation principles. Finally, we design retail rates for each rate class to generate revenue equal to each class' allocated revenue requirement. See D.P.U. 07-50 at 6-7.

Some commenters state that, rather than implementing a decoupling mechanism, the Department should focus its efforts on establishing rate structures that are more closely aligned with cost-of-service principles. We fully recognize the importance of establishing rate structures that send efficient price signals to consumers regarding: (1) the costs incurred by a company in providing distribution service to each rate class; and (2) the underlying nature of those costs (i.e., fixed costs are recovered through fixed charges, demand-based costs are recovered through demand charges, and variable charges are recovered through volumetric charges). To the extent that rates are not fully cost-based or that fixed and demand-based costs are not fully recovered through fixed charges, consumers are potentially receiving an energy price signal that departs from the theoretical ideal.

In addition, it is possible that setting distribution rates that are closer to the theoretical ideal could mitigate some of the financial disincentives that companies currently face regarding the deployment of demand resources. However, it would not address all such disincentives, and it would not eliminate the fundamental incentive companies have to increase sales (or prevent decreases in sales) once rates are set. Further, as noted by several commenters, the Department must establish rates in a manner that balances a number of key ratemaking principles – principles that reflect and address the practical circumstances attendant to any individual company's rate case. For example, any attempt to move quickly to full cost-based rates, in which a greater portion of distribution costs would be recovered through fixed rates, could have significant impacts on low usage customers, violating the principle of rate continuity, and in the short run reduce the incentive for customers to reduce their energy consumption.

Although sending efficient price signals is a fundamental objective of rate design, it is always part of the balancing applied by the Department in setting rates in a manner that is consistent with law and precedent, while reflecting the unique practical circumstances of individual companies, the realities of prevailing energy market circumstances, and the overarching public policy objectives of the Commonwealth. Contrary to the assertions or implications of some commenters, decoupling does not prevent the Department's continued adherence to cost-based principles of rate design. On the other hand, the fundamental public policy need for a decoupling mechanism can not be met simply through fully-cost-based rate design initiatives. Consequently, while the design of distribution rates based on cost-causation remains a focus and long-term objective of Department ratemaking, it does not represent an effective substitute for decoupling.

c. Lost Base Revenue Recovery or Targeted Decoupling

An LBR or targeted decoupling mechanism includes only changes in consumption that can be directly attributed to actions and activities undertaken by a distribution company. As such, a targeted decoupling mechanism requires the identification of the demand resource-related activities that will be included in the mechanism, as well as a savings level for each activity.

In theory, a targeted decoupling approach can be successful in reducing or removing the financial disincentive for distribution companies to implement a specific, pre-determined amount of demand resources. However, there will be opportunities for distribution companies to participate in a wide range of demand resource activities, both directly (e.g., the implementation of energy efficiency programs) and indirectly (e.g., the support of community-based programs such as the Cambridge Energy Alliance, the strengthening of appliance efficiency standards, the strengthening and enforcement of building codes, and the implementation of green building standards). A shortcoming of an LBR or targeted decoupling approach is that distribution companies will continue to face financial disincentives for those demand resource activities that are not specifically identified in the mechanism and, thus, will focus only on the identified activities and will be reluctant to seek or support a broader range of demand resource activities. Even if a wide range of opportunities were identified for inclusion in a targeted decoupling approach, the difficult task of determining the savings associated with each activity would remain. Indeed, if a comprehensive list of activities and associated savings were identified, a targeted decoupling approach would resemble full (or at least a partial) decoupling. Consequently, we conclude that a targeted decoupling approach will not sufficiently meet our policy objectives regarding the full deployment of all cost-effective demand resources. However, we do recognize that there may be value in using an LBR approach during a transition to full decoupling, particularly in light of the expanded demand resource programs set forth in the Green Communities Act, and present this option in Section VI.

d. Partial Decoupling

A partial decoupling approach excludes from the decoupling mechanism those changes in consumption that are unrelated to the deployment of demand resources. To implement such an approach, it is necessary to (1) identify those factors unrelated to demand resources that may cause changes in consumption patterns (e.g., weather, economic conditions, and the price of electricity and natural gas), (2) determine the level of change in consumption that results from each identified factor, and (3) normalize actual consumption to account for these factors.

In principle, a partial decoupling approach would be as effective as full decoupling in removing the financial disincentives that distribution companies currently face regarding the deployment of demand resources. This is because, under both approaches, companies' revenues would be decoupled from reductions in consumption that result from such deployment. However, as discussed by several commenters, it would be extremely difficult to quantify the relationship between consumption and factors such as economic growth. Since the manner in which actual consumption would be normalized would likely have a significant effect on a distribution company's allowed revenue, establishing these relationships would likely be a contentious, resource-intensive endeavor that could significantly increase the complexity of implementing a decoupling approach. Consequently, we conclude that the administrative burden, complexity, and potential for manipulation and error inherent in implementing a partial decoupling approach outweigh its advantages, relative to full decoupling.

e. Full Decoupling

A full decoupling mechanism separates a distribution company's revenues from all changes in consumption, regardless of the underlying cause of the changes. Full decoupling has two advantages over the targeted and partial mechanisms discussed above. First, unlike a targeted approach, full decoupling does not attempt to distinguish among the types of activities that could lead to an increased deployment of demand resources, thus comprehensively removing the disincentives the distribution companies currently face regarding such deployment. Second, unlike a partial approach, full decoupling does not attempt to distinguish between changes in consumption that are related to the deployment of demand resources and those changes that are unrelated to such deployment, thus reducing the administrative burden associated with implementing a decoupling mechanism, and resulting in a decoupling mechanism that should be transparent and easily understood. Consequently, based on our review of decoupling approaches examined in this proceeding, the Department concludes that a full decoupling mechanism best meets our objectives of (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources, and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources.

Some commenters assert that the Department need not implement any decoupling approach at the current time to achieve our objectives regarding the deployment of demand resources, stating that the current ratemaking mechanisms are sufficient. As discussed above, the Department might agree with these commenters if our objective was limited to maintaining the current level of energy efficiency resources. However, with the recent passage of the Green Communities Act, there will be a major expansion in the coming years of energy efficiency programs, demand response activities, and other demand resource applications (including distributed generation, community-based programs, and more stringent appliance standards and building codes). We also recognize that the deployment of these programs – as consistent with legislative requirements and practical realities as well as economic and administrative efficiency – will require the full support and participation of the distribution companies. Application of only the current system of shareholder incentives (and LBR for gas companies) to this broader group of demand-reducing resources would be impractical, inefficient, and possibly ineffective. The Department concludes that only a full decoupling mechanism will completely and effectively remove the disincentives that the distribution companies currently face regarding the deployment of this broad range of demand resources.

Some commenters contend that the costs associated with implementing a complex ratemaking mechanism such as decoupling would outweigh the benefits such implementation would provide. We do not agree that the costs of implementing decoupling will outweigh its benefits. First, we reaffirm that under current natural gas and electricity price conditions and forecasts, the aggressive deployment of demand resources is an essential component of the Commonwealth's energy strategy to mitigate the impact of increasing energy costs on residential, commercial, and industrial customers, including significant direct benefits to program participants as well as benefits to all customers through a dampening of natural gas and electricity commodity prices. Second, we remain convinced that the existence of an incentive for distribution companies to erect barriers to – or at least to not fully embrace – successful implementation of demand-reducing measures and actions is real, and is a byproduct of the current ratemaking approach. With the passage of the Green Communities Act, increased demand resource development in Massachusetts will have an increasingly negative impact on distribution company sales and, in this context, removing the disincentives that distribution companies currently face regarding the deployment of demand resources takes on even greater importance to ensure that we capture the benefits of advanced demand resource implementation. Third, at its core, a decoupling mechanism is just one piece of the rate design fabric. After decoupling, most major elements of a traditional ratemaking proceeding before the Department will remain largely the same (including determination of cost of service, cost allocation analyses, the establishment of a class revenue requirement, and rate design). We are persuaded that a full decoupling mechanism can be designed to minimize the complexity and cost of implementation. These design issues are discussed in the sections below.

Finally, some commenters state implementation of a decoupling mechanism may reduce the incentive for customers to pursue demand resource opportunities because to do so might lead to an increase in their electricity bill, based on the effect of decoupling. We do not accept this argument. To the extent that decoupling offsets the savings that would otherwise accrue to customers, these offsets will be de minimis and will be vastly outweighed by the benefits that customers would realize from the implementation of demand resources. The amount of incremental revenue adjustment that would need to be recovered as a result of a single customer's actions would be distributed across all ratepayers and, thus, the impact of any one customer's implementation of demand resources on his or her own bill would be too small to be noticeable. Furthermore, while decoupling might result in modest increases to the distribution portion of a customer's bill, this component only represents about one-quarter to one-third of the total bill, whereas demand resources can result in significant reductions to the customer's entire bill, including transmission and commodity costs.

f. Shareholder Incentives

The Department received a wide range of comments regarding the use of shareholder incentives to encourage distribution companies to implement energy efficiency programs. Some commenters stated that the current shareholder incentive mechanisms are sufficient to encourage distribution company energy efficiency programs and, therefore, decoupling would not be necessary for this purpose (Network Comments at 2-3).[9] The Attorney General argues

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[9] Electric and gas distribution companies are currently able to earn a shareholder incentive equal to five percent of their energy efficiency expenditures if they reach specified baseline levels of performance. Tr. 2, at 336; see e.g., Fitchburg Gas and Electric Light Company, D.T.E. 06-50, at 10-11 (2007); Energy Efficiency, D.T.E. 98-100, at §§ 5.2, 5.3 (2000). Electric companies' energy efficiency spending is mandated by statute, and the incentive is intended to both: (1) address the

(continued…)

that the existing energy efficiency shareholder incentive mechanisms seek to achieve similar goals as a base revenue adjustment mechanism and, that if decoupling were to be adopted, then the existing shareholder incentive mechanisms should be eliminated as they will be redundant, unnecessary, and unreasonable (Attorney General Comments at 24).

Many commenters state that decoupling is a necessary but not sufficient policy to encourage distribution companies to fully embrace demand resources, and that the existing energy efficiency shareholder incentives should be used in combination with decoupling (Fitchburg Comments at 17-18; WMECo Comments at 14; National Grid Comments at 6; CLF Comments at 8-9; ENE Comments at 12-13; NEEC Comments at 3, 8). Others recommend that, in addition to decoupling, shareholder incentives should perhaps be increased or expanded beyond those currently available (DOER Comments at 9; Fitchburg Comments at 17-18; Berkshire Comments at 13). DOER recommends that PBR plans include an energy savings adjustment factor that would reward or penalize the distribution company based on the level of energy efficiency savings it achieves (DOER Comments at 8, 10). Similarly, the Decoupling Consensus Group recommends that the Department allow for a system of rewards and penalties associated with achieving specific load and capacity reduction targets and deadlines (DCG Comments at 2, 4).

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[9] (…continued)
disincentive to reduce consumption created by the existing ratemaking mechanism; and (2) create an incentive for outstanding performance. See G.L. c. 25, § 19. Prior to the passage of the Green Communities Act, there was no statutory energy efficiency mandate for gas distribution companies, which have been allowed to recover LBR pursuant to a rolling-period method established by the Department. Tr. 4, at 884; see e.g., Colonial Gas Company, D.T.E. 97-112, at 32 (1999).

As noted above in Section II, the Department finds that full decoupling is necessary to encourage distribution companies to implement all available cost-effective demand resources. Shareholder incentives such as those currently used to support the energy efficiency programs will not be sufficient to overcome all the financial barriers to demand resources, eliminate the incentive to increase electricity and gas sales, and eliminate the financial penalty associated with reduced sales.

Some form of shareholder incentives can play an important role in encouraging distribution companies to implement demand resources after decoupling is implemented. While decoupling eliminates financial barriers that distribution companies face in implementing demand resources, it does not provide any positive financial incentive for their implementation. However, a final determination of the role and amount of shareholder incentives for demand resources is beyond the scope of this generic investigation. Such a determination should be based on a more detailed discussion of the role of distribution companies in implementing specific types and amounts of demand resources, as well as the types of incentive mechanisms that might be appropriate after the implementation of decoupling.

In addition, we note that Section 11 of the Green Communities Act, amending G.L. c. 25 by inserting Section 21(b)(2)(v), allows electric and gas distribution companies to make proposals for shareholder incentive mechanisms in their energy efficiency plan filings. The Green Communities Act does not provide any detail on how such mechanisms should be structured or how much money should be made available for shareholder incentives. We expect that shareholder incentive proposals will be discussed and reviewed by the members of the Energy Efficiency Advisory Council[10] and will eventually be filed with the Department for approval along with the efficiency programs proposed in the forthcoming energy efficiency plans.

We encourage electric and gas distribution companies to submit proposals for shareholder incentives in future filings of their energy efficiency plans. In so doing, we expect companies to be mindful of the Department's long-standing policy that energy efficiency shareholder incentive mechanisms should be designed in such a way as to strike the appropriate balance between (a) promoting effective, successful efficiency programs, and (b) protecting the interests of electricity and gas customers. D.T.E. 98-100, at 37 (November 3, 1999).

IV. <u>MECHANICS OF DECOUPLING</u>

A. <u>Introduction</u>

The Department's straw proposal for determining a distribution company's allowed revenue requirement raised three key concerns among commenters. First, commenters state that under our straw proposal, the reconciliation of actual revenues to a revenue target allows a distribution company's revenues to increase as a result of growth in the number of customers but does not allow revenues to increase as a result of growth in usage per customer, which they contend fails to ensure that distribution companies will be neutral to changes in sales volumes. Second, commenters argue that the implementation of PBR plans and other reconciling cost

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[10] Section 11 of the Green Communities Act creates an Energy Efficiency Advisory Council that will consist of an eleven-member panel composed of industry stakeholders. The Council is tasked with, among other things, facilitating the development of, reviewing, and approving state-wide efficiency and demand resource program plans and budgets, which will be submitted by the distribution companies every three years.

tracking mechanisms must continue after the implementation of decoupling in order for distribution companies to recover all of their prudently incurred costs. Finally, commenters suggest that a distribution company's allowed revenue target does not have to be determined through a fully-litigated, future base rate proceeding involving an in depth review of a company's cost of service, cost allocation and rate design. The first two concerns are discussed in this section, infra, along with the proposed use of a future test year. The need for and content of rate case filings in order to implement a decoupling mechanism is addressed in Sections VI and VII, below.

B. Distribution Cost Drivers

1. Introduction

In D.P.U. 07-50, the Department proposed a base revenue adjustment mechanism designed to "better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives." D.P.U. 07-50, at 11. We proposed that each distribution company recover a fixed amount of revenues per customer, for each customer class, which would ensure that revenues are more closely aligned with the number of customers – a significant driver of costs on their distribution systems. Id. at 4, 12-15. The Department proposed to determine each distribution company's allowed revenues per customer in its next base rate proceeding. Id. at 13. We stated that certain features of current rate plans (e.g., PBR plans, as well as reconciling charges for pension costs, post-retirement benefits other than pensions ("PBOP"), and supply-related bad debt) may no longer be necessary or appropriate after a distribution company implements its base revenue adjustment mechanism. Id. at 5, 13. Finally, we proposed that, in order to ensure no financial harm from reduced sales and no financial benefits from increased sales, each distribution company's base revenues would be reconciled on an annual basis. Id. at 4, 14-15.

2. Summary of Comments

a. Number of Customers, PBRs, Cost-Tracking Mechanisms

Commenters generally disagree with the Department's proposal to adjust a distribution company's revenue requirement based only on the number of customers. They assert that the Department has cited no basis for the assumption that there is a direct correlation between the number of customers and distribution company costs (Fitchburg Comments at 4; NSTAR Comments at 17; WMIG Comments at 3, 7). For example, WMIG contends that the number of customers is largely irrelevant to the overall cost of service for distribution companies and, instead, argues that the major cost drivers of a distribution company's system are demand and overall energy usage (WMIG Comments at 7; WMIG Reply Comments at 7-8; Tr. 3, at 524-525).

Most commenters state that the proposed decoupling approach would fall short of the Department's stated objective to render gas and electric distribution companies neutral to changes in sales volumes (NSTAR Comments at 10; National Grid Comments at 7-8; WMECo Comments at 3-4; Fitchburg Comments at 4). They state that, because the traditional rate-setting model in Massachusetts is based on an historic test year cost-of-service, distribution companies implicitly rely on revenue growth from increased demand and energy usage to fund ongoing expenses and needed investments (Fitchburg Comments at 3-4; NSTAR Comments at 9-11; National Grid Comments at 7-8;WMECo Comments at 3; Tr. 3, at 540, 626, 654, 687-688; Tr. 4, at 743). Commenters assert that, while growth in sales revenues between rate cases does result from growth in the number of customers, a distribution company's revenue stream also is increased by growth in usage per customer. By adjusting annually only for the number of customers on a system, commenters state that the Department's straw proposal ignores the revenue from growth in usage per customer, which means that the proposal will not ensure that distribution companies are neutral to changes in sales volumes (NSTAR Comments at 4-5; National Grid Comments at 7-8; Fitchburg Comments at 4; WMECo Comments at 3-4; Tr. 3, at 540, 621, 654-655, 663).

Commenters who were critical of our proposed approach state that the proposal is a revenue recovery mechanism and not a cost recovery mechanism (Fitchburg Comments at 3; WMECo Comments at 3; PEG Comments at 5, 17, 19; Concentric Comments, by Reed, at 13-14). Commenters argue that distribution companies rely upon increased revenue from load growth to pay for increased capital expenditures as well as increased operations and maintenance ("O&M") costs. A number of commenters predict that distribution companies will need to seek frequent rate relief if revenue from load growth is eliminated (National Grid Comments at 6-7; WMECo Comments at 3; NSTAR Comments at 19, 21-22, 26; PEG Comments at 16; Tr. 3, at 664). A number of gas distribution companies state that they are already concerned about lost revenue associated with the decline in usage per customer over the last fifteen years, which makes it extremely difficult to recover costs for much needed capital investment in a system that is aged and aging (National Grid Comments at 8-9; Bay State Comments at 11-12, 14; NSTAR Comments at 5-6, 16, 20; Concentric Comments, by Simpson, at 7-9; Tr. 3, at 514, 517, 540; Tr. 5, at 1058). Commenters argue that to ensure that distribution companies recover all of their prudently incurred costs and avoid frequent rate case filings, the target revenue level and the number of customers should be determined annually and adjusted for: (1) inflation; (2) capital investments; and (3) significant unpredictable and uncontrollable costs (Fitchburg Comments at 5; WMECo Reply Comments at 3; NSTAR Comments at 17-18, 21; Bay State Reply Comments at 4; Berkshire Reply Comments at 4; DOER Reply Comments at 12; ENE Reply Comments at 9; Concentric Comments, by Reed, at 21-24; Tr. 1, at 218).

With regard to the Department's proposal to eliminate PBR, some commenters state that the continuation of existing long-term plans is necessary as a matter of fundamental fairness, arguing that the early termination of a PBR plan would deprive the distribution company of the benefits expected to occur in the later years of the plan (Bay State Comments at 5, 32; Berkshire Comments at 6-7; Tr. 4, at 881; Tr. 5, at 1134). PEG points to the absence of a link between the Department's proposed revenue recovery mechanism and subsequent changes to distribution company costs after the test year. PEG states that our straw proposal sets a fixed base year target revenue per customer but does not take into account upward pressures on costs over time, which means that the straw proposal does nothing to mitigate these costs and offers no substitute for PBR adjustments (PEG Comments at 2, 17-19). PEG adds that if the revenue recovery mechanism was implemented without PBR, pressures on costs would likely accelerate and distribution companies would be forced to file base rate applications more frequently to recover costs (PEG Comments at 2, 19). PEG concludes that eliminating PBR would undermine many of its positive objectives, including incentives for cost control, flexible and efficient pricing, efficient allocation of resources, incentives for innovation, and lower regulatory costs (PEG Comments at 2, 10-15, 19-22).

Accordingly, a number of commenters argue that the Department should adopt a ratemaking method that permits both PBR and decoupling to work together (Bay State Reply Comments at 3-4; Berkshire Comments at 1-2, 12; Berkshire Reply Comments at 4; DOER Comments at 8; DOER Reply Comments at 7, 12; National Grid Comments at 13; DCG Reply Comments at 6; ENE Comments at 11; E2 Comments at 2). Commenters in favor of including both components state that decoupling is compatible with PBR and may be more effective when paired with PBR or another cost recovery mechanism because decoupling focuses on revenue recovery, while PBR focuses on distribution company costs (Bay State Comments at 32; Berkshire Comments at 1-2; Berkshire Reply Comments at 4; CLF Comments at 2, 8-9; E2 Comments at 2; ENE Comments at 12-13; NEEC Comments at 3, 8; PEG Comments at 2, 5, 7, 17; WMECo Comments at 12-13; Tr. 3, at 659-660; Tr. 5, at 1165). PEG argues that: (1) PBR provides a long-term perspective which considers increasing costs; and (2) the Department has evaluated PBR vis-a-vis traditional cost of service regulation and concluded that cost of service regulation had numerous defects (PEG Comments at 5, 12-13, 20-24, citing Incentive Regulation, D.P.U. 94-158 (1995)). Bay State asserts that decoupling addresses changes in a gas distribution company's average use per customer, while PBR addresses changes in unit costs (Bay State Reply Comments at 4). NSTAR contends that O&M, construction, and maintenance costs typically increase at a rate equal to or greater the rate of inflation and that it is impossible for a distribution company to recover its annual revenue requirement without a cost recovery mechanism like a PBR (NSTAR Comments at 17-18, 25-26). NSTAR asserts that PBR would: (1) adjust the level of revenues commensurate with inflation; and (2) protect against revenue erosion associated with costs outside its control (NSTAR Comments at 17-18, 25-26).

Finally, commenters are divided regarding the future use of fully reconciling cost recovery mechanisms. Several commenters argue that these mechanisms should continue under a decoupling regime because revenue decoupling is not a substitute for these cost-trackers which were implemented to recover uncontrollable and unpredictable expenses (Berkshire Comments at 12; Bay State Comments at 28; Fitchburg Comments at 5, 8; NSTAR Comments at 10, 32; National Grid Comments at 13-14; Concentric Comments, by Reed, at 19, 24). In contrast, the Attorney General recommends that, in order to strengthen the price signals necessary to achieve the Department's policy objectives, the Department must eliminate all cost recovery mechanisms that she considers to be obsolete under a revenue decoupling mechanism (Attorney General Comments at 22). Such mechanisms include: (1) PBOP; (2) price cap adjustments, including exogenous cost adjustments; (3) the residential assistance adjustment factor; and (4) capital addition reconciling mechanisms (id. at 22-23). She also proposes that the Department eliminate various ratemaking conventions, such as the use of year-end rate base and inflation allowances, because she argues that these conventions would no longer be necessary for a company to maintain earnings stability (id. at 23).

b. Use of a Future Test Year

As an alternative to the Department's proposal, National Grid offers a different approach to determine a distribution company's base revenue requirement – the use of a future test year. Instead of relying on the number of customers as the Department had proposed, National Grid recommends establishing a distribution company's base rate revenue requirement through a forecasted rate-year method, which it claims is a more effective means of ensuring the alignment of distribution company costs and revenues than an historic test year (National Grid Comments at 7; National Grid Reply Comments at 7).[11] National Grid proposes that distribution companies set revenue requirements based on a three-year forecast of: capital investment; O&M expenditures; administrative and general expenses; depreciation; and taxes (National Grid Reply Comments at 4).[12] National Grid asserts that these elements would be examined in the same manner as in a base rate proceeding using an historic test year (id. at 4-6). National Grid proposes that rates be calculated based on a three-year forecasted revenue requirement and a three-year forecast of sales which would incorporate changes in

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[11] At the panel hearings, National Grid provided an illustrative example of its decoupling proposal based on a forward test year and later submitted a revised version to the Department on November 13, 2007 (Tr. 5, at 1003-1060; National Grid Illustrative Decoupling Proposal, November 13, 2007).

[12] WMECo proposes a similar approach that uses forecasted data for three years for revenue and sales and sets a revenue requirement for three years (WMECo Reply Comments at 3).

customer energy usage from: (1) distribution company-sponsored energy efficiency programs; (2) other energy efficiency and demand-side resources; and (3) expected growth in the number of customers (id. at 4). National Grid proposes that billed revenues for a given year be reconciled annually against the forecasted revenue requirement for that year in order to ensure that a distribution company recovers no more and no less than the total targeted revenue for the year, regardless of actual sales growth or decline (id.).

National Grid claims that the use of a future test year in setting base rates would be more effective in removing the disincentive for distribution companies to promote energy efficiency and other demand-side resources because: (1) it more closely aligns distribution costs and revenues; and (2) it accounts for increasing capital investment, costs, and expenses (id. at 6). National Grid contends that basing rates on a future test year is not a radical change from the current practice and that future test years are currently being used by FERC, as well as in a number of states, including California, New York, and Connecticut (id. at 5).

Some commenters support National Grid's proposal to use a future test year method in establishing a base rate revenue requirement. Reasoning that the implementation of a full decoupling mechanism would eliminate all revenues resulting from load growth, these commenters argue that the Department should shift from an historic to a future test year in order to ensure that distribution companies are able to undertake the necessary capital investments for continued reliability (DCG Reply Comments at 7). The DCG asserts that a forecasted rate year will allow a distribution company's revenue requirement to more closely track its costs because a company can: (1) better account for needed capital investments; and

(2) factor the effects on sales from the expansion of energy efficiency and DSM programs into their sales forecasts, which are then used to set rates (id. at 8). Also, DCG argues that factors such as inflation and productivity gains that currently are accounted for in PBR plans could be directly incorporated into a forecasted test year or, alternatively, separate PBR-like mechanisms accounting for inflation, productivity, and anticipated capital investments could be overlaid on the future test year (id.).

Other commenters reject National Grid's proposal to use a future test year in establishing a base rate revenue requirement, citing a variety of flaws. The Attorney General and the Network argue that the use of a future test year would constitute a sharp departure from the Department's longstanding, well-established approach for setting base rates and reconciling revenues (Attorney General Reply Comments at 29; Network Reply Comments at 4). DOER cautions that the determination of a distribution company's annual revenue requirement has critical components that need fuller discussion than has been afforded through this proceeding (DOER Reply Comments at 9, 12). The Network contends that a future test year approach would diminish a distribution company's existing incentive for operational efficiency between rate cases and would not allow sufficient review of investments which must be shown to be used, useful, and prudently incurred (Network Reply Comments at 4). The Attorney General argues that an historic test year allows for review of actual costs incurred by a distribution company but a future test year would not require any specific costs to be actually incurred, making its cost estimates "subjective improvable guesstimates" (Attorney General Reply Comments at 30). The Attorney General contends that the adoption of a future test year will result in a number of consequences, including: (1) increased regulatory complexity; (2) endless litigation over the forecast of each operating expense and capital expenditure; (3) the pre-approval of cost recovery for each distribution company; (4) significant efforts by the Department and interveners to investigate all cost aspects; and (5) daunting and impossible rate case proceedings, which consume the time and resources of the Department and other parties (id. at 30-31). The Attorney General concludes that the future test year would be based on complicated distribution company-generated data which are susceptible to bias and difficult to verify which, therefore, could have detrimental effects on the due process rights of parties (Attorney General Reply Comments at 31, citing Massachusetts Electric Company, D.P.U. 18204 (1975); Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 676 n.1 (1981); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); Eastern Edison Company, D.P.U. 1580, at 19 (1984)).

Bay State asserts that it is not opposed in concept to National Grid's future test year proposal but seeks the opportunity to investigate the approach further so that its mechanics can be clarified (Bay State Reply Comments at 8). Bay State argues that a ratemaking mechanism addressing aging infrastructure is critical, because it would allow a gas distribution company to recover the prudently incurred costs of maintaining safety and reliability (id.). Bay State contends, however, that this may be best accomplished through a reconciling adjustment within the local distribution adjustment clause rather than through a future test year (id.).

3. Analysis and Conclusions

a. Number of Customers, PBRs, and Cost-Tracking Mechanisms

Historically, under our existing ratemaking policy, distribution companies experienced sales growth from an increased number of customers and growth in usage per customer.[13] Between rate cases, distribution companies have the opportunity to use the increase in revenues from sales growth to pay for, among other things, increasing O&M costs, as well as to fund system reliability and capital expansion projects. With the implementation of revenue decoupling, revenue from growth in usage per customer would be eliminated. In D.P.U. 07-50, we proposed the annual reconciliation of actual revenues to a revenue target, which allows a distribution company's revenues to increase as a result of growth in the number of customers but not for growth in usage per customer.

A change in the number of customers served is a significant driver of the change in the cost to operate gas and electric distribution systems, but it does not capture all of the reasons for changes in costs associated with providing distribution services (Tr. 3, at 597, 618, 621, 626, 647; Tr. 4, at 852-853). To the extent that distribution companies make capital expenditures to replace existing assets, the magnitude of capital replacement required has little or no correlation with levels of customer growth. Instead, capital expenditures are influenced by factors such as the age of the assets, changes in technology, past patterns of customer

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13 Recently, however, sales growth has been greater for electric distribution companies than for gas distribution companies because energy consumption per customer has been trending upward for electric distribution companies and has been trending flat or downward for gas distribution companies (Company responses to Information Request DPU 1-1(d)).

growth, and increases in the load to serve. Under these conditions, distribution companies' rates may not adequately provide for recovery of capital replacement expenditures that are incurred after the rate year if the reconciliation of revenues is based solely on a customer growth adjustment. While we expect that expanded energy efficiency programs will forestall the need for incremental infrastructure investment, we cannot conclude at this time that these programs will lead to the avoidance of all such investment. A decoupling mechanism should not undermine a distribution company's ability to obtain adequate funding for needed infrastructure maintenance and upgrade projects.

An increase in the costs to provide distribution service can also occur as a result of inflationary pressures between base rate proceedings. In an effort to control costs, increase efficiency, and keep distribution companies out of rate cases for a reasonable period of time, the Department has approved various PBR plans that adjust a company's rates and associated level of revenues commensurate with inflation. The Department's straw proposal set a fixed revenue target per customer for each distribution company and, therefore, does not account for possible upward cost pressures in the revenue target. Eliminating an inflation adjustment to revenues could, in theory, lead to more frequent rate case filings to the extent a distribution company's ability to recover its allowed revenue requirement in the years after a rate case diminishes. To avoid this result, the Department will not force the termination of a currently effective PBR plan prior to the end of its term.

Accordingly, in view of our discussion above with respect to the elimination of revenues associated with the growth in use per customer, as well as the potential for an increase in distribution service costs because of inflation, the Department will not require distribution companies to reconcile actual revenues to a revenue target based solely on the number of customers. Instead, we will consider company-specific ratemaking proposals that account for: (1) the impact of capital spending on a company's required revenue target; and (2) the inflationary pressures with respect to the prices of goods and services used by distribution companies. We recognize that circumstances will vary from company to company and, as such, we will permit a certain amount of flexibility when establishing a revenue requirement for a distribution company. Such ratemaking proposals could be similar in structure to the PBR rate plans that most electric and gas companies have in place today. As always, such proposals must be fully supported, and the distribution company will have the burden of proof to demonstrate the reasonableness of its proposal.

Regarding the continuation of fully reconciling cost recovery mechanisms after decoupling, the Department notes that at the time these mechanisms were approved, we found that the costs to be recovered were volatile and fairly large in magnitude, were neutral to fluctuations in sales volumes, and were beyond the control of the companies. See NSTAR Electric & Gas Company, D.T.E. 03-47-A, at 25-28, 36-37 (2003); Bay State Gas Company, D.T.E. 05-27, at 183-186 (2005). As circumstances change, the Department will consider which, if any, of these currently reconciled costs should continue to be fully reconciled via a separate mechanism or recovered instead via base rates. Such consideration will take place on a case-by-case basis, in which each distribution company must demonstrate that continued recovery in a separate mechanism is warranted.

b. Use of a Future Test Year

We now address the proposal that a distribution company's base rate revenue requirement be determined through the use of a future test year. It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. See Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); New England Telephone &Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). In establishing rates pursuant to G.L. c. 164, § 94, the Department examines a test year which usually represents the most recent twelve-month period for which complete financial information exists, on the basis that the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval.

We disagree with commenters who suggest that a future test year would not represent a radical change from our current ratemaking practice. It would. The Department has previously considered and declined to adopt proposals to determine a distribution company's base revenue requirement on the basis of a forecasted test year. We have done so due to concerns about the time and resources needed to litigate all projected costs, revenue, and sales items, as well as the forecasting methods used to determine such projections. While National

Grid argues that establishing distribution rates based on the future test year would most closely align a distribution company's revenues with costs, we have previously stated that the "Department views the adoption of the future test year as fraught with speculation and uncertainty . . . [and there] are too many variables which affect the cost of service to justify employing a future test period." D.P.U. 18210, at 2-3. Our reluctance to rely on projections of future results is based on the "well-grounded apprehension that subjective factors will result in unreliable results." D.P.U. 18264, at 2. The Department has previously stated that a future test year "could have detrimental effects on the rights of due process of parties to its proceedings." D.P.U. 1580, at 19. Also, given limited resources, we have stated that the six-month statutory suspension period for reviewing a company's rate filing may not provide adequate time to review forecasts relating to expenses and revenues, the projection methods, or other factors associated with a future test year method. Id. The Department's right to choose an historic test year in determining base rates instead of a future test year has been upheld by the Massachusetts Supreme Judicial Court.[14]

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[14] As stated by the Massachusetts Supreme Judicial Court in New England Telephone & Telegraph Company v. Department of Public Utilities, 371 Mass. 67, 71 (1976),

> we stand by our prior decisions that the Department, although not required to use a method based on an adjusted historic test year, is permitted to do so. New England Telephone & Telegraph Company v. Department of Public Utilities, 327 Mass. at 84, 97 N.E.2d 509; New England Telephone & Telegraph Company v. Department of Public Utilities, 331 Mass. at 624, 121 N.E.2d 896; New England Telephone & Telegraph Company v. Department of Public Utilities, 360 Mass. at 452, 275 N.E.2d 493. Cf. Boston Gas Co. v. Department of Public Utilities, 336 N.E.2d 713 (1975); Note, The Use of the Future Test Year in

(continued...)

The Department's application of an historic test year to establish rates has served ratepayers well, and the record in this proceeding does not prompt us to abandon a clear policy that has existed for many decades. Using the actual financial results of the most recent twelve-month period as a test year constitutes sound, long-standing regulatory practice, a practice rooted in foundational principles of regulatory economics and public policy. In light of these considerations and findings, the Department finds that implementation of revenue decoupling does not require, and would not necessarily benefit from, moving to a future test year.

C. Reconciliation of Target Revenues to Actual Revenues

1. Introduction

In D.P.U. 07-50, at 14-16, the Department proposed methods of determining and reconciling actual revenues against target revenues for each rate class. The Department proposed that a distribution company's annual reconciliation filing include, for each rate class: (1) the level of revenues; (2) the proposed adjustment to the base energy charge; (3) the projected number of customers to be served during the recovery period; and (4) the projected customer, energy, and demand billing determinants for the recovery period. Id. at 16.

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14 (...continued)
Utility Rate-Making, 52 B.U.L.Rev. 791, 809 (1972). Our "fundamental law requires no particular theory or method to be used in determining a rate base, provided the resulting rates are not confiscatory." Boston Gas Company v. Department of Public Utilities, 324 N.E.2d 372 (1975).

2. Summary of Comments

There is general consensus among the commenters that reconciliations should be performed on a distribution company-wide basis, rather than by rate class as the Department had proposed (National Grid Comments, App. A at 2-5; DCG Reply Comments at 5; ENE Reply Comments at 4; Berkshire Company Reply Comments at 5; Tr. 4, at 809-811, 929). ENE argues that reconciling revenues on a company-wide basis would protect customers in small, heterogeneous rate classes from bearing burdensome costs due to changes in customer count within a rate class (ENE Reply Comments at 4). Berkshire adds, however, that a company-wide reconciliation should exclude any rate classes that are ineligible for a company's energy efficiency programs (Berkshire Company Reply Comments at 5).

3. Analysis and Conclusions

While the Department's original proposal was to reconcile target revenues with actual revenues for each rate class, our review of comments in this proceeding leads us to conclude that such a reconciliation mechanism may be in conflict with the Department's rate design goal of continuity. Customers in a small heterogeneous rate class should not be unduly impacted by events such as customer migration or significant reductions of load due to aggressive implementation of demand resources by customers in the same rate class. For example, if revenues decrease because a large commercial customer installed on-site generation, the remaining customers in that rate class may see a disproportionate increase in rates compared to the other rate classes.

To address this concern, we will require that the revenue reconciliation be performed on a company-wide basis. The amount of revenues to reconcile will be calculated for each individual rate class, but the total amount of reconciled revenues will be either recovered from or returned to all rate classes on a uniform, per kilowatt-hour ("kWh") basis. Reconciling revenues on a company-wide basis will reduce the likelihood that one customer class experiences a disproportionate change in rates as compared to other rate classes. Because adjustments would be spread over all rate classes, reconciling revenues on a company-wide basis would also address concerns about rate discontinuity for smaller customers as compared with large customers. This approach should also address concerns about rate volatility in general resulting from revenue reconciliation.

Accordingly, each distribution company shall propose a base rate adjustment mechanism that reconciles target to actual revenues for each rate class in order to determine the total revenues to be reconciled. This total reconciliation amount will then be recovered from or returned to all customers uniformly across all rate classes on the basis of the company's total kWh sales.

D. Adjustments to Base Rate Charges

1. Introduction

In D.P.U. 07-50, at 15, the Department proposed that distribution companies recover the reconciliation of target and actual revenues through adjustments in the energy component of their distribution rates. Under the proposal, each distribution company would, for each rate class, calculate: (1) the target revenue for the upcoming year (including the reconciliation amount from the previous year); and (2) the revenues that it projects to recover from the rate class' customer and demand charges (as applicable).[15] The difference between the rate class' target revenues and the revenues projected to be recovered through the customer and demand charges would be recovered through the class' distribution energy charge, using projected energy billing determinants for the upcoming year. Id.

2. Summary of Comments

Many commenters support the Department's straw proposal and state that any over- or under-recovery should be flowed through to rates via the volumetric charges (Bay State Comments at 30; Compact Comments at 8; NEEC Comments at 6; Comverge Comments at 9; DOER Comments at 6; ENE Comments at 9; CLF Comments at 7; WMECo Comments at 7-8; National Grid Comments, App. B at 4; Fitchburg Comments at 11-12; DCG Reply Comments at 10). Commenters state that an adjustment to volumetric charges would send the proper price signals to customers (Comverge Comments at 9; DOER Comments at 6; CLF Comments at 7; WMECo Comments at 7-8; DCG Reply Comments at 10; ENE Reply Comments at 7). Other commenters favor an adjustment to volumetric charges because it will be simple for ratepayers to understand (Compact Comments at 8; NEEC Comments at 6; ENE Comments at 9; National Grid Comments, App. B at 4).

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15 Distribution companies shall calculate each rate class' projected customer and demand charge revenues using: (1) the charges approved by the Department in the company's most recent base rate proceeding; and (2) the projected customer and demand billing determinants for the upcoming year.

In contrast, some commenters disagree with the Department's straw reconciliation proposal. The Attorney General argues that making an adjustment to volumetric charges sends the wrong price signal to customers because a customer who lowers consumption may nonetheless experience an increase in per unit energy costs (Attorney General Comments at 41). PEG states that adjusting the volumetric charges will increase price volatility (PEG Comments at 24). Instead, PEG argues that reconciliation revenues should be recovered through the customer charge, which would be more consistent with sound ratemaking principles and would lead to more efficient pricing structures (PEG Comments at 25).

Synapse and TEC argue that the Department should determine how to make adjustments in each company's base rate proceeding (TEC Comments, by Synapse, at 17; TEC Comments at 3). NSTAR suggests that each company be permitted to file a revenue-neutral rate redesign that will incorporate the Department's rate design goals (NSTAR Comments at 29). Berkshire states that a separate adjustment mechanism should be established by the Department to true-up any difference between target and actual revenues (Berkshire Comments at 8).

3. Analysis and Conclusions

Reconciling revenues through a customer charge rather than a volumetric charge will not encourage conservation among customers because a customer's reduction in energy consumption will not serve to offset an increase to the customer charge, which is a fixed charge. In theory, customers should be exposed to prices that reflect as closely as possible long-run incremental costs. Costs that are relatively fixed should be recovered through fixed charges, while costs that are variable should be recovered through volumetric charges. These price signals should in turn lead customers to consume (and conserve) products at a level that will lead to the most economically efficient outcome.

However, it is clear that, at least from the perspective of demand resource investments, the response of electricity and gas customers to price signals is not well aligned with economic theory. There are a variety of market barriers that limit the way that electric and gas customers can or do respond to price signals. These market barriers prevent customers from modifying their consumption or adopting cost-effective efficiency measures to the extent that would lead to the economically efficient outcome. Examples of market barriers to energy efficiency include lack of information about efficiency measures or opportunities, limited availability of efficiency products, high transaction costs of adopting efficiency measures, limited access to capital or financing necessary to adopt efficiency measures, split incentives between renters and landlords, and institutional barriers for large consumers.[16] The Department has long recognized that these market barriers prevent customers from adopting efficiency measures and that customers cannot be expected to respond to price signals in a way that leads to the most economically efficient outcome. Indeed, these market barriers are one of the primary reasons that electric and gas companies need to implement energy efficiency programs. See e.g., Electric Generation, D.P.U. 86-36-F at 9 (1988).

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16 Also, in order for customers to consume products at the economically efficient level, the prices they are exposed to should include all costs, including those associated with social externalities (such as environmental costs not internalized via emission control programs).

In light of these market barriers, the limitations of price signals, and the Department's need to balance the application of various ratemaking principles including cost causation, rate continuity, rate stability, and administrative efficiency, the Department finds that it is appropriate to recover reconciled revenues through a volumetric charge, specifically the energy component of the distribution charge. Putting these revenues in this component of the distribution charge will provide customers with a greater incentive to reduce their energy consumption and will further the goal of promoting demand resources. The Department expects that, in most instances, the amount of the change to the distribution charge will be small relative to a customer's total bill and, thus, this price signal will be small. Nonetheless, we believe that this approach is appropriate because it moves customer incentives in the appropriate direction and should be easier for customers to understand.[17]

Finally, we note that the Attorney General argues that applying the reconciled revenues to a volumetric charge would send the wrong price signal to customers because a customer who lowers consumption may nonetheless experience an increase in per unit energy costs. However, as discussed above in Section V, we expect that the impact on any one customer's distribution charge as a result of his or her own actions to reduce sales is likely to be unnoticeable because the reconciled revenues will be recovered from all customers. Further,

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17 We note that the reconciliation will sometimes reduce customers' charges whenever there is a net increase in sales per customer. In these circumstances, customers will see a lower distribution charge as a result of the revenue reconciliation and will have slightly less incentive to reduce sales. However, with electric and gas distribution companies pursuing increasingly aggressive levels of demand resources, we expect that revenue reconciliation will lead to increased distribution charges more often than reduced distribution charges.

we agree with the Attorney General that the total dollar change in the final bill resulting from the reconciliation of revenues lost from *all* customers is likely in most cases to be de minimis, and reiterate that any increase in the distribution price due to a customer's actions to reduce consumption will likely be vastly outweighed by the savings on the customer's total bill.

E. Reconciliation Period

1. Introduction

In D.P.U. 07-50, at 14, the Department proposed that distribution companies reconcile actual revenues with target revenues on an annual basis. In addition, the Department described the information that should be included in the annual reconciliation filings. Id. at 16. Specifically, we proposed that the filings describe, with supporting documentation, the proposed reconciliation amounts, including, for each rate class: (1) actual billed revenues during the reconciliation period; (2) allowed revenues per customer; (3) number of customers served during the reconciliation period; (4) the reconciliation amount from the previous reconciliation period; and (5) any other revenue adjustments provided for in the base revenue adjustment mechanism. Id.

The Department also proposed that distribution companies submit a quarterly filing that includes actual and target revenue information, both for the quarter, and cumulatively to that point within the reconciliation period. Id. The Department stated that if, at the end of any quarter, the cumulative difference between the actual and allowed revenues falls outside of a pre-determined percentage range, the distribution company would be required to adjust its base energy charge to recover or refund the amount of the difference that falls outside of the acceptable range. Id.

2. Summary of Comments

Most commenters agree with the Department's proposal to perform the reconciliation of target versus actual revenues on an annual basis (Compact Comments at 6, NEEC Comments at 5, NSTAR Comments at 23; Attorney General Comments at 39; Blackstone Comments at 4; ENE Comments at 6; ENE Reply Comments at 4; TEC Comments, by Synapse, at 16; TEC Comments at 2-3; CLF Reply Comments at 6; National Grid Comments, App. B at 2, 4; WMECo Comments at 5; DCG Reply Comments at 5; Bay State Comments 29). Synapse and TEC claim that a reconciliation period of less than one year would be unduly burdensome on all parties (TEC Comments, by Synapse, at 16; TEC Comments at 3).

Other commenters disagree with the Department's proposal to perform annual reconciliations. Some commenters argue that quarterly or semi-annual reconciliations may be necessary to meet the Department's goals of rate stability, rate continuity, and administrative efficiency (Comverge Comments at 8; DOER Comments at 5; Fitchburg Comments at 10). Berkshire contends that annual reconciliations would be appropriate for a distribution company with a straight fixed-charge rate design but, if a company has a mix of fixed and variable charges, the reconciliation period may need to be more frequent (e.g., semi-annually) to avoid large adjustments and to send the proper price signals to customers (Berkshire Comments at 6).

With regard to rate changes, many commenters suggest that the Department establish a threshold level that must be exceeded before any rate change is permitted (Attorney General Comments at 42; ENE Comments at 9; TEC Comments, by Synapse, at 16; TEC Comments at 2-3; National Grid Comments, App. B at 2,4; WMECo Comments at 8; Fitchburg Comments at 10; NSTAR Comments at 27). The Attorney General recommends that if the adjustments for any one year are greater than three percent of total expected distribution revenue recovery, then the Department should open an investigation to review the totality of a company's cost of service and revenues to ensure that rates are just and reasonable (Attorney General Comments at 42).

3. Analysis and Conclusions

Currently, annual reconciliation filings are made by a total of twelve Massachusetts electric and gas distribution companies. The Department initially proposed that actual revenues be reconciled with target revenues on an annual basis out of concern that a reconciliation period of less than one year could prove overly burdensome for the agency and other interested parties. It would require significant additional resources from the Department, distribution companies, and other interested parties to investigate multiple decoupling reconciliations in the course of a single year. While quarterly or semi-annual reconciliations might better meet the Department's rate design goals of earnings stability, rate continuity, and efficiency, we find that annual reconciliations in combination with interim adjustments, as discussed below, will sufficiently address these concerns.

We agree with several commenters who suggest that our proposal for distribution companies to make quarterly informational filings on their base rate adjustment mechanism could be overly burdensome. Therefore, to further the goal of administrative efficiency, we will not require quarterly informational filings.

We are also persuaded by commenters who urge us to establish a threshold percentage change in revenues where, when exceeded, a distribution company must petition the Department for an interim reconciliation. Annual reconciliations assume that the annual rate adjustment will be small. Thus, establishing a threshold percentage change in revenues that will trigger an interim rate adjustment should protect ratepayers from large annual rate changes.

Accordingly, if a distribution company's actual revenues are ten percent above or below the target revenues, as established in either a base rate proceeding or an annual reconciliation proceeding, that company must petition the Department for an interim adjustment prior to its next scheduled annual revenue reconciliation. We find that this ten percent threshold strikes an appropriate balance between protecting customers from large or frequent rate changes, protecting distribution companies from large swings in revenues between annual reconciliations, and preventing an overly burdensome number of interim adjustments. If, however, experience proves otherwise, the Department may revisit this threshold value.

V. EFFECT OF DECOUPLING ON COMPANY RISK

A. Introduction

The Department's standard for determining a company's allowed return on equity ("ROE") is set forth in Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope"). According to the Bluefield and Hope standards, the allowed ROE should: (1) preserve a company's financial integrity; (2) allow it to attract capital on reasonable terms; and (3) be comparable to returns on investments of similar risk.

In our Order opening this investigation, the Department noted that changes in the means by which a distribution company recovers its allowed revenues, such as the proposed base revenue adjustment mechanism, could materially alter the distribution of risks among the distribution company, its shareholders, and its customers. D.P.U. 07-50, at 17. The Department proposed determining risk on a company-by-company basis, but stated that this investigation would consider whether it is appropriate to establish common principles or guidelines concerning how any new base revenue adjustment mechanism could affect the distribution of risks and a distribution company's allowed ROE. Id.

In addition, during the course of this proceeding, the Department posed a number of questions related to the feasibility of adjusting a company's capital structure to recognize any reduction in risk associated with decoupling revenues from sales (Tr. 5, at 1109-1110). Under this approach, a company's allowed ROE would remain unchanged, but its common equity ratio would be reduced for ratemaking purposes to correspond with any lower investor risk perceived by a decoupling mechanism (Tr. 5, at 1114-1115).[18] If a company's capital structure were adjusted, the lower investor risk arising from decoupling would be incorporated into rates without the need to quantify an appropriate reduction to ROE.

B. Summary of Comments

1. Comments Opposed to Adjusting ROE

Numerous commenters oppose any predetermined adjustment for risk related to decoupling (Bay State Comments at 31; Berkshire Comments at 11; Concentric Comments, by Reed, at 2; Comverge Comments at 9-10; Fitchburg Comments at 14-15; NSTAR Comments at 30-31; National Grid Comments, App. A at 9-10; New England Gas Comments at 5-6; WMECo Comments at ii). Some commenters maintain that decoupling would not necessarily result in a reduction in risk (Bay State Comments at 31; Berkshire Comments at 11; Comverge Comments at 9-10). National Grid suggests that it is inappropriate to establish guidelines that assume decoupling mechanisms result in reduced risk (National Grid Comments, App. A at 9-10). Other commenters recommend a comprehensive review before adjusting ROE for any

[18] For example, assuming that a company has a 50-50 debt-to-equity ratio, with a cost of debt of 8.0 percent and an ROE of 11.0 percent, the required overall rate of return ("ROR") would be 9.5 percent. Assuming that the implementation of a decoupling mechanism reduced the company's required ROE to 10.5 percent, the required ROR would decrease to 9.25 percent. If a regulating commission elects to recognize the lower overall risk through capitalization adjustments instead of reducing the company's ROE, the imputed capital structure would consist of approximately 52 percent debt and approximately 48 percent common equity.

change in risks related to decoupling (Berkshire Comments at 11; Fitchburg Comments at 14-15; New England Comments at 5-6; WMECo Comments at ii, 9-10).

Concentric contends that there is no evidence suggesting that decoupling lowers investors' required returns and, in fact, investors' required returns are unaffected by the implementation of decoupling mechanisms, as evidenced by recent ROE allowances approved by regulatory agencies in states where decoupling has been implemented (Concentric Comments, by Reed, at 29-30). Concentric conducted a stock price-to-book ("P/B") ratio analysis comparing distribution companies that have decoupling mechanisms in place to a group of peer companies that do not have decoupled rates in place, in order to test for any change in valuation resulting from the decoupling of revenues from sales (Concentric Comments, by Reed, at 27). Concentric reviewed stock prices for 30 trading days prior to the issuance of a regulatory decision approving decoupling and 30 trading days after such a decision was rendered (Concentric Comments, by Reed, at 27-29; Tr. 5, at 1016). Concentric argues that, based on its analysis, there was no sustained increase in the relative P/B ratios of companies that adopted decoupling mechanisms. Accordingly, Concentric concludes that investors have already factored in the effects of decoupling in their investment decisions (Concentric Comments, by Reed, at 27-31).

Concentric further suggests that decoupling mechanisms are widespread and now considered status quo, at least for gas companies (Concentric Comments, by Reed, at 30-31). Concentric states that, out of approximately 25 regulatory commission decisions, only one decision by the Maryland Public Service Commission made an explicit reduction to allowed

ROE related to decoupling (Concentric Comments, by Reed, at 30-31; Tr. 5, at 1035-1036).[19] Concentric claims that any analysis of a distribution company's required ROE must consider the relative risk of the subject company in comparison to a peer group, including the revenue- and cost-side mechanisms used by the peer group members (Concentric Reply Comments at 6). According to Concentric, while companies with decoupling mechanisms do not experience any lowered investment risk, a company that does not have a decoupling mechanism is presently perceived to have greater investment risk (Concentric Comments, by Reed, at 30-31; Concentric Reply Comments at 4-5; Tr. 5, at 1025).

Concentric argues that it would be inappropriate to assume a per se reduction in the required ROE for distribution companies as a result of decoupling (Concentric Comments, by Reed, at 4; Concentric Reply Comments at 3). Concentric acknowledges that decoupling will reduce risk to distribution company shareholders (Tr. 5, at 1008-1011; Concentric Comments, by Reed, at 13). However, according to Concentric, decoupling mechanisms simply serve to offset the greater volatility or risk on revenues associated with (1) price-induced conservation; (2) greater appliance and equipment efficiency; and

[19] Concentric asserts that the Maryland Public Service Commission has made explicit reductions in allowed ROE (Tr. 5, at 1035-1036; 1041-1042; see In the Matter of the Application of Potomac Electric Power Company, Order No. 81517, Case No. 9092, at 72 (2007)). Additionally, Concentric states that staff at the New York Public Service Commission and the Public Counsel before the Washington Utilities and Transportation Commission have recommended decreases ranging from ten to 15 basis points (Tr. 5, at 1035-1036, 1041-1042). However, these recommendations do not appear to have been specifically adopted by the respective commissions (Tr. 5, at 1035-1036; see e.g., In the Matter of the Application of Avista Corporation d/b/a Avista Utilities, Docket UG-060518, Order 04 (2007)).

(3) reductions in customer demand from accelerated conservation programs (Concentric Reply Comments at 3; Tr. 5, at 1008-1009). Concentric claims that distribution companies continue to face growing risks associated with price, policy mandates, weather, and infrastructure needs, which offset any perceived reduction in risk associated with decoupling mechanisms (Tr. 5, at 1011-1012).

Some commenters caution that distribution companies may actually face new and unforeseen risks resulting from decoupling, depending upon the particular decoupling mechanism selected (Blackstone Comments at 7; NSTAR Comments at 31). For example, Blackstone contends that a decoupling mechanism based on historic revenues per customer is likely to raise concerns about the distribution company's ability to achieve its allowed ROE on a consistent basis (Blackstone Comments at 7). NSTAR notes that the deferral mechanism contained in Maine's decoupling plan resulted in large deferrals that became "politically unacceptable" to recover, thus resulting in significant shareholder costs (NSTAR Comments at 31). Comverge postulates that decoupling mechanisms may actually require an increase in allowed ROE in order to: (1) provide incentives for certain behavior; or (2) to mitigate against penalties that may be imposed in an associated performance incentive mechanism (Comverge Comments, at 9-10).

2. Comments in Support of Adjustments to ROE

Some commenters support adjusting relative risk because of decoupling, at least in principle (Attorney General Comments at 40-41; Attorney General Reply Comments at 14-20; Compact Comments at 10; CLF Comments at 7-8; DOER Comments at 7; Network Reply

Comments at 4-5). The Network argues that decoupling brings increased revenue stability, such that fairness to customers requires that allowed ROE be reduced if decoupling is implemented (Network Reply Comments at 4). Similarly, the Attorney General contends that decoupling mechanisms bring about reduced earnings volatility, thereby reducing investment risk (Attorney General Reply Comments at 14-15). The Attorney General holds that this reduced investment risk will decrease the required return to the distribution companies (id. at 15). The Attorney General urges that, to the extent that the Department adopts any decoupling scheme, distribution rates must be reduced at the same time to recognize this reduction in risk (id.).

DOER cautions that the Department may need to avail itself of more information on how capital markets react to a decoupling mechanism before proposing any adjustments to ROE (DOER Comments at 7). ENE urges that the overall effect of any decoupling mechanism on ratepayers be considered in determining the magnitude of any change in resulting risk (ENE Comments at 11). Some commenters in support of the Department's general risk adjustment proposal suggest that the best approach to assess the effect of decoupling on distribution company risk is to examine the issue in a fully-litigated rate case, where the arguments and analysis can be vetted with consideration of a distribution company's individual circumstances (Attorney General Reply Comments at 19-20; Compact Comments at 10; CLF Reply Comments at 7).

The Attorney General disputes the conclusions of Concentric's P/B analysis and points out perceived flaws in Concentric's logic. The Attorney General claims that Concentric's analysis demonstrates little beyond the fact that shareholder expectations of regulatory decisions are formed well in advance of any regulatory order (id., citing Tr. 5, at 1023-1024). The Attorney General reasons that unexpected regulatory outcomes are more likely to shape investor perceptions and, thus, drive short-term stock prices (id.). The Attorney General also disputes Concentric's contention that the risks associated with decoupling work only in one direction (id. at 19). She contends that Concentric's assumptions defy basic financial theory and are based on "self-serving" comments from the investment community (id.).

3. Capitalization Adjustments

With respect to adjusting a distribution company's capital structure to recognize the reduction in risk associated with decoupling, the Network supported the concept in principle (Network Reply Comments at 4-5). However, most commenters who expressed a view on capitalization adjustments indicate that, while capitalization imputation is theoretically sound, this approach raised a number of practical problems. For example, the Attorney General notes that almost all Massachusetts gas and electric distribution companies are wholly owned subsidiaries of holding companies (Tr. 5, at 1113-1115). Concentric states that, for these companies, the effect of decoupling is more likely to be factored into the particular company's cost of debt rather than its required ROE (id. at 1116-1117). The Attorney General and Concentric also express concerns about whether a regulatory commission has the legal authority to impose a specific capital structure, as distinct from imputation of one for ratemaking purposes (id. at 1121-1122). The Attorney General also perceives practical difficulties with maintaining a target debt-to-equity ratio because of ongoing changes in capitalization, such as in the retained earnings balance (id. at 1122). Finally, Concentric contends that the investment community would perceive capitalization adjustments as identical to actual reductions to allowed ROE unless it was demonstrated that the difference was offset by a lower risk caused by greater leverage in the capital structure (id. at 1119).

C. Analysis and Conclusions

As noted above, a distribution company's allowed ROE should: (1) preserve its financial integrity; (2) allow it to attract capital on reasonable terms; and (3) be comparable to returns on investments of similar risk. While empirical analyses are typically used in setting an ROE, the Department has long recognized that their use is not an exact science. A number of judgments are required when conducting a model-based ROE analysis, and each level of judgment to be made contains the possibility of inherent bias and other limitations. Bay State Gas Company, D.T.E. 05-27, at 302 (2005); Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 229 (2002); Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977); Boston Gas Company, D.T.E. 03-40, at 363 (2003); D.P.U. 18731, at 59; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 15 (1978). While the results of analytical models are useful, the Department must ultimately investigate any proposed ROE and apply its own judgment and expertise to the evidence gathered on all relevant factors during a rate case to determine an appropriate rate of return. Our task is both qualitative and quantitative, and evidence-based, and is not merely a mechanical or model-driven exercise. These realities make it exceedingly difficult to come to specific conclusions concerning the potential importance or magnitude of any single element of risk relevant to setting a company's ROE.

Commenters are divided on the extent to which decoupling mechanisms have affected investor perceptions of risk. Some commenters go so far as to suggest that: (1) investors perceive decoupling as the status quo; and (2) the market expects companies without decoupling mechanisms to merit higher ROE as compensation (Concentric Comments, by Reed, at 30-31; Tr. 5, at 1025). The P/B analysis performed by Concentric to support this proposition is insufficient to draw any conclusions with regard to the effect of decoupling on investor risk and required returns. Shareholders are presumed to be familiar with the regulatory climate in which distribution companies operate as well as the basic elements of the rate setting process. As a result, investor expectations as to the general outcomes of rate cases and their many components, including proposed decoupling mechanisms, are likely to have been formed well in advance of actual regulatory decisions. Moreover, the decoupling mechanisms referenced by Concentric range from simple weather normalization adjustments to more comprehensive mechanisms (Tr. 5, at 1036). Any analysis of the effects of decoupling on investor risk perceptions must take into account both the regulatory and investment climates, as well as the particular decoupling mechanism under consideration.

Decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales, and do not increase from undue increases in sales. See D.P.U. 07-50, at 1-2. Thus, by definition, decoupling reduces earnings volatility (see Concentric Reply Comments at 2; Attorney General Reply Comments at 16-17). Assuming everything else remains the same, such reduction in earnings volatility should reduce risks to shareholders and, thereby should serve to reduce the required ROE.

Concentric argues that the reduction in shareholder risks created by decoupling is offset by increasing risks in the electricity and gas industries, including increasing risks as a result of (1) price-induced conservation, (2) greater appliance and equipment efficiency, (3) reductions in customer demand from passive and active accelerated conservation programs, and (4) weather (Concentric Reply Comments at 3; Tr. 5, at 1011-1012). Distribution companies may be exposed to increasing risks in the future, as a result of these changes or other changes in the electric and gas industries. We make no findings on specific risk factors here, either present or future risks, as such considerations need to be made in the context of a company's rate case. However, it is important to note that if the changes identified by Concentric (reduced demand from efficiency activities and increased volatility due to weather) were to occur in the future, the risks associated with these changes would essentially be eliminated by the decoupling mechanism that we are establishing with this order.

Any quantification of a change in risk due to decoupling is subject to a wide range of considerations, including a company's own risk characteristics, the risk characteristics of the comparison group used to evaluate the required ROE, and the nature and details of the particular decoupling mechanism (Tr. 5, at 1040-1041, 1084, 1114-1115). This detailed evaluation of risk and ROE is typically performed as part of a rate case. Essex County Gas Company, D.P.U. 87-59, at 68 (1987); Boston Gas Company, D.P.U. 1100, at 135-136 (1982); New Bedford Gas and Edison Light Company, D.P.U. 20132, at 35-36 (1980). Any attempt to quantify the effect of decoupling on risk in a generic sense is beyond the scope of this current investigation.

The Department will consider the impact of a decoupling mechanism for a distribution company along with all other factors affecting that company's required ROE in the context of a rate proceeding, where the evidence and arguments may be fully tested. Accordingly, each distribution company must include an analysis of the effects of decoupling on its required ROE as part of the direct testimony submitted as part of any base rate application to implement decoupling. See Section VII, below. Such analysis must be provided as part of the company's case-in-chief; a generalized statement that such risk had been considered in determining the proposed ROE will not be sufficient.

Further, we do not accept Comverge's argument that a distribution company's required ROE may have to be increased to compensate for the risk of any performance-related penalties that could be included with a decoupling mechanism. The Department has previously addressed this issue with regard to service quality standards. In that instance, we found that a distribution company has no legitimate claim to a higher ROE based upon a purported risk of failing to meet its service quality performance requirements. See Service Quality Standards, D.T.E. 99-84, at 50 n.38 (2000) and cases cited therein.

Finally, in the course of this proceeding, we considered whether the imputation of capital structures to recognize changes in risk associated with decoupling produces a clear advantage over more direct ROE adjustments (Tr. 5, at 1113-1114, 1116-1117, 1119). Several commenters raised both legal and practical issues with this proposed approach (id.

at 1121-1122). Moreover, the Massachusetts Supreme Judicial Court has found that the imputation of a capital structure for ratemaking purposes may only be done if the company's capitalization is found to be so unreasonable and at odds from usual practice as to impose an unfair burden on consumers. Mystic Valley Gas Co. v. Department of Public Utilities, 359 Mass. 420, 428-430 (1971); Boston Gas Co. v. Department of Public Utilities, 359 Mass. 292, 301-302 (1971). Therefore, the Department will not employ capitalization imputation as a substitute for adjustments to ROE solely for the purpose of adjusting for changes in risk associated with the implementation of decoupling.

VI. TRANSITION TO DECOUPLING

A. Introduction

In this section, the Department describes the expected transition to the implementation of full decoupling mechanisms for all electric and gas distribution companies in Massachusetts. We will address, among other things, the treatment of existing rate plans and the establishment of initial rates for companies' decoupling mechanisms.

B. Summary of Comments

1. Base Rate Proceedings

Commenters were sharply divided on whether a base rate proceeding is necessary to implement decoupling. Many commenters encourage the Department to move forward expeditiously, arguing that there is no need for litigated base rate proceedings to implement decoupled rates (Bay State Comments at 5, 27; Berkshire Comments at 2, 4; Blackstone Gas Comments at 3; CLF Comments at 1, 4; Concentric Comments, by Reed, at 17; DCG Reply

Comments at 9; DOER Comments at 3; DOER Reply Comments at 2-3, 6; Fitchburg Comments at 4; National Grid Comments at 3-6, 17-19; NEEC Comments at 2-3, 8; New England Gas Comments at 3-4, 5; NSTAR Comments at 1-3, 23; WMECo Comments at 2). These commenters claim that the Department has already determined that their existing rates are just and reasonable and that the adjudication of a new base rate proceeding would: (1) be costly; (2) cause significant scheduling and administrative burdens; and (3) unnecessarily delay the implementation of decoupling. These commenters contend that requiring a base rate proceeding would be both inefficient and unfair because it would exclude investments made to achieve long-term savings under existing rate plans and incentive mechanisms (Bay State Comments at 27; Berkshire Comments at 2-4; Blackstone Comments at 3-4; CLF Comments at 4, 9; Comverge Comments at 6; Concentric Comments, by Reed, at 16-18; New England Gas Comments at 3-5; NSTAR Comments at 11-16, 24).

Concentric argues that requiring a base rate proceeding prior to the implementation of decoupling would consume a significant amount of time and other resources and it is not feasible for all distribution companies to file rate cases at one time (Concentric Comments, by Reed, at 17). Concentric adds that base rate proceedings are not necessary for the implementation of decoupling, and requiring them would undermine the Commonwealth's goal to offset annual increases in electricity demand with equivalent energy-efficiency and conservation measures by 2010 (id.). Concentric suggests that if the Department's stated desire to reset or reexamine current base rates is driven by concerns about unjust earnings, this could be addressed by an earnings-sharing mechanism, with a collar based on the allowed ROE from the most recent rate case (id. at 19).

Bay State and New England Gas state that they have recently completed rate proceedings and argue that the benefit to customers of immediate decoupling outweighs any additional precision that could be achieved from re-litigating their allowed revenues (Bay State Comments at 5, 27; New England Gas Comments at 4).[20] Bay State argues that because incentive rate plans are intended to reduce long-term costs, requiring a base rate proceeding as a prerequisite to decoupling would send a negative signal to distribution companies and the capital markets, which could be avoided by layering any decoupling adjustment mechanism on top of existing rate structures (Bay State Comments at 27).

In contrast, for various reasons, a number of commenters state that if the Department decides to pursue decoupling, then fully-litigated base rate proceedings for all distribution companies are mandatory (Attorney General Comments at 6, 28-29; Attorney General Reply Comments at 20-23, 23; AIM Comments at 11; Compact Comments at 4; ENE Reply Comments at 5; Network Comments at 7; TEC Comments, by Synapse, at 2; WMIG Comments at 11). The Attorney General asserts that while the Department can make general policy statements regarding the implementation of decoupling outside of a rate case, it cannot suggest specific changes to rates without base rate proceedings (Attorney General Comments at 6, 28-29; Attorney General Reply Comments at 20-21, 23). ICARE recommends that an

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20 New England Gas notes that it recently received its first base rate increase since the mid-1990s as part of a rate settlement approved in New England Gas Company, D.P.U. 07-46 (2007) (New England Gas Comments at 3).

important determination such as establishing decoupled rates should be subject to the rigorous investigation of a base rate proceeding (ICARE Comments at 2, 4). Noting that several distribution companies have not had a rate proceeding for many years, AIM claims that, without the benefit of a detailed rate case and cost allocation study, it would be impossible to adequately support any revenue enhancements for the distribution companies (AIM Comments at 10). Finally, the Network recommends a rate proceeding to set the cast off rates for each distribution company (Network Comments at 7).[21]

With regard to timing or sequence of full rate proceedings for distribution companies, commenters made various suggestions. TEC argues that the Department should schedule rate proceedings according to each distribution company's estimated magnitude of "untapped potential" for demand resources and the length of time since its last general rate case (TEC Comments, by Synapse, at 2, 14, 19). The Compact suggests that the Department require each distribution company, in order of decreasing customer count, to file a rate proceeding. The Compact adds that it is critical to start with updated and verified costs to assess, among other things, the impact on revenues caused solely by demand resources (Compact Comments at 4). ENE states that, once a base rate adjustment mechanism is established, adjustments can be made periodically without the need for a separate proceeding, adding that the Department should focus first on the distribution companies with the greatest numbers of customers and, therefore, the greatest impact on customer costs (ENE Comments at 5, 12).

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21 The Network also emphasizes the importance of protecting low-income customers when sales decline, because the vast majority of these households will experience rate and bill increases with decoupling (Network Comments at 7).

2. Existing Rate Plans

Commenters are generally opposed to any forced termination of existing rate plans in order to implement decoupling. Concentric and DCG state that legal and policy considerations outweigh the early termination of Department-approved rate plans (Concentric Comments, by Reed, at 16; DCG Reply Comments at 9). Concentric notes that a number of electric and gas distribution companies have rate plans in place with several years remaining in the term of the plan (Concentric Comments, by Reed, at 16). Concentric states that there are certain legal concerns relating to this issue, but did not elaborate on what these concerns might be (id.).

Various commenters suggest phased approaches to expedite the transition to decoupled rates. DOER suggests that, as a first phase, the Department should use existing rate plans or settlements to establish the allowed revenue by rate class for the initial year (DOER Reply Comments at 10-11). Thus, distribution companies with existing PBR plans would continue to adjust rates annually based on the approved PBR formulas until the end of the PBR plan term (id.). DOER suggests that, in the second phase, the Department should require each distribution company to update its revenue requirement and determine the annual PBR adjustment formula through a full base rate proceeding (DOER Comments at 9; DOER Reply Comments at 11).

Alternatively, National Grid recommends a different, phased approach for the transition to decoupling. National Grid suggests that, in the first phase, the Department direct all distribution companies to file an LBR recovery mechanism within 90 days of a final Order in this proceeding, reasoning this is the fastest way to remove all existing disincentives that prevent distribution companies from expanding energy efficiency, demand response programs, distributed generation, and renewable energy (National Grid Comments at 3-5, 17-19; National Grid Reply Comments at 9).[22] During the first phase, National Grid suggests that the Department develop a schedule for each distribution company to transition from the use of an LBR mechanism to a permanent decoupling ratemaking structure, taking into account the terms of the existing rate plans (National Grid Comments at 4, 17-19). National Grid suggests that, in its second phase, the Department: (1) require each distribution company, in its next base rate filing, to propose a new decoupling mechanism; and (2) place all distribution companies on a periodic rate case schedule once existing plans expire or are renegotiated, with fully reconciling decoupling mechanisms (id. at 4-5, 17-19). Ceres suggests an approach similar to the approach proposed by National Grid – initially proceeding with a temporary LBR mechanism, followed by the implementation of a permanent decoupling mechanism (Ceres Reply Comments at 3).

Concentric suggests that the Department allow distribution companies with current rate plans to elect whether to calculate target revenues each year based on approved index-based rate plan adjustments, until the conclusion of the rate plan (Concentric Comments, by Reed, at 17-18). Concentric recommends that for distribution companies whose rate plan is near the

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[22] Similarly, as a short-term measure, WMECo suggests that the Department compensate distribution companies for lost revenue through an LBR mechanism in order to reduce the disincentive to implementing energy efficiency measures (WMECo Reply Comments at 6). WMECo, however, opposes an LBR mechanism as a long-term solution, without elaborating on its reasons (WMECo Reply Comments at 6).

date of termination or who does not have a currently effective rate plan, target revenues should be calculated by alternative means, without specifying what those means would be (id.).

C. Analysis and Conclusions

In our Order opening this investigation, the Department highlighted the value of a base rate proceeding in implementing a decoupling mechanism, stating that in setting initial rates that would satisfy our statutory obligations and ratemaking precedent, we "must understand the company's underlying distribution revenue requirement and allocation of this revenue requirement among customer classes through an allocated cost of service study." D.P.U. 07-50, at 14. As discussed above, the Department has the authority to implement a decoupling mechanism so long as the rates established by this mechanism are just and reasonable. Additionally, as we recognized in D.P.U. 07-50, at 10

> changes or adjustments to any ratemaking structure can lead to a significantly different distribution of equity and risks between the company and its customers, between classes of customers, among customers within a given rate class, and across time. The changes contemplated in this proceeding cannot be done in a piecemeal fashion if they are to meet the Department's objectives.

Mechanically, decoupling can be viewed as a straightforward adjustment in the context of what is otherwise a traditional ratemaking structure. Nonetheless, the move to decoupling represents an important and meaningful departure in form and purpose from how the Department has set and implemented distribution company rates for decades. While we believe the rationale and need for taking this step is strong, we do not take it lightly. Consequently, we believe that layering a decoupling mechanism on top of a distribution company's existing rates, as some commenters suggest, would constitute the piecemeal approach that we seek to avoid. While each distribution company's existing rates were found to be just and reasonable after a full base rate proceeding or as a result of a negotiated settlement, the Department can not conclude that it is appropriate to use these as initial rates for decoupling without investigating issues related to cost allocation, rate design, and cost reconciling mechanisms. In addition, there are several issues that were raised but could not be fully explored in this generic docket (e.g., cost drivers, shifting risk profiles) which will need to be explored in the context of distribution company-specific rate cases.

The Department seeks to expeditiously remove the economic disincentives for distribution companies to deploy demand resources in their service territories. We believe that stating our clear intent to implement decoupling for all distribution companies over the next several years, in conjunction with the transition approach described below, strikes an appropriate balance between the need to ensure that the rates that result from companies' decoupling mechanisms are just and reasonable, and the need to quickly remove disincentives to the deployment of demand resources. A key component of this approach is the short-term use of LBR recovery which, while not appropriate as an efficient long-term ratemaking solution, can serve as a useful tool to accommodate an orderly transition to the implementation of decoupling for all distribution companies. Such a transition must take into account the rate plans under which many distribution companies currently operate, as well as the Department's ability to manage the investigation of decoupling rate case filings in an efficient manner. Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company, D.T.E. 99-19-1, at 10 (1999).

As we stated in Section IV, above, the Department will not force the termination of a currently effective rate plan prior to the end of its term. The Department will allow the voluntary termination of a rate plan prior to the end of its term in order to implement decoupling. Any distribution company with a rate plan that is the result of a settlement must obtain the necessary agreement of all signatories to the settlement before the plan can be terminated.

Beginning in 2009 and extending through the term of their initial three-year energy efficiency plans (i.e., through 2012),[23] electric distribution companies will be allowed to recover LBR resulting from their incremental efficiency savings.[24] For this purpose, incremental efficiency savings are defined as those efficiency savings that exceed the efficiency savings from their 2007 energy efficiency activities, as documented in their 2007 annual reports on energy efficiency. An electric distribution company that seeks to recover LBR must petition the Department to do so in conjunction with the filing of its 2009 energy efficiency plan. Such filing must include full documentation and explanation of (1) how the incremental energy efficiency savings will be achieved and accounted for, and (2) the proposed LBR calculation. Gas distribution companies, which currently are allowed recovery of LBR, may

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23 Pursuant to Section 11 of the Green Communities Act, all electric and gas distribution companies are required to file three-year energy efficiency plans. The term of the initial plans covers 2010 through 2012.

24 The opportunity to recover LBR applies only to electric companies until they begin operating under a decoupling plan.

continue do so through the term of their initial three-year energy efficiency plans (i.e., through 2012) consistent with existing LBR recovery methods.[25]

The allowance of LBR recovery through the term of the initial three-year energy efficiency plans is consistent with our expectation that, with limited exceptions, distribution companies will be operating under decoupling plans by year-end 2012. Distribution companies that are subject to PBR or rate plans that extend past 2012, and that do not voluntarily terminate such plans before their expiration, will be allowed to recover LBR through the remainder of their existing rate plans.

If, as a result of this Order, the Department is faced with a number of simultaneous requests to implement decoupling, it may be necessary in the interests of administrative efficiency and in recognition of available resources for the Department to issue a schedule to govern the timing of the investigation of company decoupling. Accordingly, in order for the Department to consider whether and to what extent such scheduling may be needed, within 45 days of the date of this Order, each distribution company must notify the Department of when the company expects to file a rate case to implement decoupling.

VII. RATE CASE FILING REQUIREMENTS

As discussed in Section VI, above, decoupling will be implemented for each distribution company through a base rate proceeding consistent with the Department's well-established precedent regarding cost-of-service, cost allocation, and rate design.

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25 The opportunity to recover LBR applies only to gas companies until they begin operating under a decoupling plan.

See D.P.U. 07-50, at 4-5. In addition to all supporting testimony and data customarily filed in a base rate proceeding, each company also must include information necessary to support the implementation of its proposed decoupling mechanism, consistent with the Department's directives in this Order.[26] At a minimum, this information should include the following:

- the company's determination of its proposed initial target revenues per customer for each rate class;

- the factors that the company proposes to use to adjust annually its target revenues for each rate class;

- the manner in which the company's proposed mechanism treats customers receiving new distribution service during a particular year, to the extent that the company determines that the costs of providing service to new customers differs from the costs of providing service to existing customers;

- a tariff showing the manner in which the company proposes to (1) annually reconcile actual versus target revenues, and (2) recover its annual target revenues through rates;

- whether the company proposes a specified period of time between the effective date of the initial rates and the filing of its subsequent base rate case (similar to a PBR term) and, if so, how this is taken into account in other components of its proposed mechanism; and

- the manner in which the company has taken into account in the determination of its proposed ROE, the effect that implementation of its proposed decoupling mechanism will have on its risk profile.

As a final matter, with regard to the filing of settlement agreements, the Department has previously stated "[a]s a general matter, the presentation of a settlement proposal in a

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26 In addition, companies' filings should identify those costs that currently are recovered outside of base rates through a reconciliation mechanism. Companies that seek to continue the reconciliation of these costs must demonstrate that such recovery is warranted (see Section IV.B.3, above).

given docket does not diminish the Department's need for adequate time to consider and investigate the underlying facts, data, assumptions, calculations, rate design, and policy considerations that are explicit or implicit in the proposed settlement. The Department expects that any company seeking to file a settlement will anticipate the Department's need to conduct an orderly, full evaluation of the settlement and related issues." Southern Union Company, D.P.U. 07-46, at 10 (2007). See also Western Massachusetts Electric Company, D.T.E. 06-55, at 25-26 (2006). This perspective takes on added importance given the gravity and complexity of factors raised in this Order and the many related issues raised by the move to decoupled rate structures, and because of the overriding importance of establishing rates that are just and reasonable. In light of this, the Department will not implement decoupling under any circumstances without the development of a full evidentiary record.

VIII. CONCLUSION

We initiated this proceeding to determine what, if any, changes are necessary to current ratemaking practices in order to reduce the financial disincentives that electric and gas companies face regarding the deployment of demand resources in their service territories. D.P.U. 07-50, at 1. The Department proposed a full decoupling mechanism that would comprehensively sever the link between revenues and sales, thus rendering the distribution companies' revenue levels immune to change in sales between rate proceedings. We requested comments on the straw proposal, including (1) whether a full decoupling mechanism is necessary to accomplish the Department's objectives vis-a-vis the efficient deployment of demand resources, (2) the details associated with implementing a decoupling mechanism, and

(3) the effect that implementation of a decoupling would have on a company's risk, and the manner in which such effects should be reflected in a company's ROE.

Based on our review of the written comments and comments made by participants in the panel hearings, the Department has made the following findings in this Order:

- Full decoupling completely and effectively removes the disincentives that distribution companies currently face regarding expanded deployment of demand resources. Other ratemaking alternatives such as base rate redesign, LBR recovery (or targeted decoupling), partial decoupling, and shareholder incentives do not sufficiently address the issue of disincentives (Section III).

- Factors such as inflation and capital spending requirements may be taken into account when determining the annual revenue that companies will be allowed to recover through their decoupling mechanisms, with a certain amount of flexibility provided to companies to take into account their specific circumstances (Section IV.B).

- The implementation of a decoupling mechanism does not require, and would not necessarily benefit from, moving from the Department's well-established policy regarding the use of historic test years to establish rates to using a future test year approach (Section IV.B).

- Reconciliation of target revenues to actual revenues should occur on a company-wide basis to ensure that customers in one rate class do not see a disproportionate change in rates compared to customers in other rate classes (Section IV.C).

- Annual reconciliations should be collected from customers through distribution energy charges to provide customers with a greater incentive to reduce their energy consumption and, thus, further the goal of promoting the deployment of demand resources (Section IV.D).

- Annual reconciliations, in combination with interim adjustments (as necessary), will best meet the Department's rate design goals of earnings stability, rate continuity, and efficiency. A company must petition the Department for an interim rate adjustment when the difference between its actual and target revenues exceeds ten percent (Section IV.E).

- Because decoupling is designed to ensure that companies' revenues are not affected by changes in sales, it should reduce risks to shareholders, all else being equal. However, the quantification of the effect of decoupling on a company's ROE is subject to a wide range of considerations that are typically evaluated as part of a rate case (Section V).

- Implementation of a company's decoupling mechanism requires the Department to (1) investigate issues related to cost allocation, rate design, and cost reconciling mechanisms, and (2) address issues that were not fully explored in this proceeding (e.g., cost drivers, shifting risk profiles). The Department expects that companies will have operational decoupling plans by year-end 2012 (Section VI).

- To accommodate an orderly transition to the implementation of decoupling, distribution companies will be permitted to recover incremental energy efficiency-related LBR through the term of their initial three–year energy efficiency plans, or until they have implemented decoupling, whichever occurs first. For electric companies, LBR recovery will be based on incremental savings that exceed 2007 savings levels. For gas companies, existing LBR recovery methods will remain unchanged (Section VI).

With these findings, the decoupling mechanism established today is an essential first step towards eliminating the barriers that the Commonwealth's gas and electric distribution companies now face regarding the deployment of demand resources in their service territories.

IX. ORDER

Accordingly, after due consideration, it is

ORDERED: That all gas and electric distribution companies shall comply with the directives contained in this Order.

By Order of the Department,

/s/

Paul J. Hibbard, Chairman

/s/

W. Robert Keating, Commissioner

/s/

Tim Woolf, Commissioner

X. APPENDICES

Appendix 1 - Comments filed on September 10, 2007

Associated Industries of Massachusetts ("AIM")

Attorney General of the Commonwealth ("Attorney General")

Bay State Gas Company ("Bay State")

The Berkshire Gas Company ("Berkshire")

Blackstone Gas Company ("Blackstone")

Cape Light Compact ("Compact")

Comverge, Inc. ("Comverge")

Concentric Energy Advisors, on behalf of: Bay State, Fitchburg, New England Gas, NSTAR Electric, NSTAR Gas, and WMECo (together, "Concentric")

Conservation Law Foundation ("CLF")

Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (together, "Constellation")

CURRENT Group, LLC ("Current")

Commonwealth of Massachusetts Division of Energy Resources ("DOER")

Environmental Entrepreneurs ("E2")

EnerNOC, Inc. ("EnerNOC")

Environmental Northeast ("ENE")

Fitchburg Gas & Electric Company d/b/a Unitil ("Fitchburg")

Greater Boston Real Estate Board ("GBREB")

Ipswich Citizens Advocating for Renewable Energy ("ICARE")

Intech 21, Inc. ("Intech 21")

Low-Income Weatherization and Fuel Assistance Program Network ("Network")

Energy Consumers Alliance of New England d/b/a Massachusetts Energy Consumers Alliance ("Mass Energy")

Massachusetts Food Association ("Mass Food")

Massachusetts Hospital Association ("MHA")

Massachusetts Electric Company, Nantucket Electric Company, and KeySpan Energy Delivery New England d/b/a National Grid ("National Grid")

Massachusetts Chapter of the National Association of Industrial and Office Properties ("NAIOP")

Northeast Energy Efficiency Council ("NEEC")

New England Gas Company ("New England Gas")

NSTAR Electric Company and NSTAR Gas Company (together, "NSTAR")

Pacific Economics Group, Inc. on behalf of: Bay State, Berkshire, Fitchburg, New England Gas, NSTAR Electric, NSTAR Gas, and WMECo (together, "PEG")

Retail Energy Supply Association ("RESA")

Retailers Association of Massachusetts ("RAM")

The Energy Consortium ("TEC")

Wal-Mart Stores East, L.P. ("Wal-Mart")

Western Massachusetts Industrial Group ("WMIG")

Western Massachusetts Electric Company ("WMECo")

Appendix 2 - Participants in Public Hearings

AIM

Attorney General

Bay State

Berkshire

Compact

Comverge

Concentric

CLF

Current

DOER

E2

EnerNOC

ENE

Fitchburg

GBREB

Intech 21

Network

National Grid

NSTAR

PEG

RESA

TEC

Wal-Mart

WMIG

WMECo

Appendix 3 - Reply Comments filed on December 4, 2007

AIM

Attorney General

Bay State

Berkshire

Ceres (“Ceres”)

Compact

Concentric

CLF

Decoupling Consensus Group, on behalf of: Comverge, CLF, E2, ENE, National Grid; New England Clean Energy Council, NEEC, NSTAR, and WMECo (together, “DCG”)

DOER

E2

ENE

Network

National Grid

RESA

TEC

Wal-Mart

WMIG

WMECo